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IN THE

Supreme Court of the United States

PUGET SOUND ENERGY, INC., AVISTA CORPORATION, AVISTA ENERGY, INC., CONSTELLATION ENERGY COMMODITIES GROUP, INC., IDACORP ENERGY L.P., MORGAN STANLEY CAPITAL GROUP INC., PORTLAND GENERAL ELECTRIC COMPANY, POWEREX CORP., SEMPRA ENERGY TRADING LLC, SHELL ENERGY NORTH AMERICA (US), L.P., AND TRANSCANADA ENERGY LTD.,
Petitioners,

v.

PEOPLE OF THE STATE OF CALIFORNIA, ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Ninth Circuit

PETITION FOR A WRIT OF CERTIORARI

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QUESTIONS PRESENTED

1. Whether the Ninth Circuit – in conflict with the decisions of at least four other circuits – erred in holding that the Federal Energy Regulatory Commission's ("FERC") use of a pre-enforcement evidentiary proceeding to inform its decision whether to enforce § 206 of the Federal Power Act, 16 U.S.C. § 824e, subjected to judicial review that agency's otherwise unreviewable choice not to initiate a § 206 enforcement proceeding.

2. Whether the Ninth Circuit deviated from the settled administrative law of other circuits by interfering with FERC's discretion to structure its own proceedings in ordering FERC to consider in one proceeding matters that FERC had determined were more properly addressed in a separate and ongoing proceeding.

3. Whether the Ninth Circuit, in conflict with the deferential approach in other circuits to reviewing agency interpretations of administrative complaints, exceeded its authority by rejecting FERC's interpretation of an administrative complaint that accorded with the complainant's own interpretation and was based on the entire context of the complaint.

LIST OF PARTIES TO THE PROCEEDINGS

Petitioners Puget Sound Energy, Inc., Avista Corporation, Avista Energy, Inc., Constellation Energy Commodities Group, Inc. (f/k/a Constellation Power Source, Inc.), IDACORP Energy L.P., Morgan Stanley Capital Group Inc., Portland General Electric Company, Powerex Corp., Sempra Energy Trading LLC (f/k/a Sempra Energy Trading Corp.), Shell Energy North America (US), L.P. (f/k/a Coral Power, L.L.C.), and TransCanada Energy Ltd. participated in the proceedings before the Federal Energy Regulatory Commission ("FERC") and were intervenors in the court of appeals proceedings.

Respondent FERC was the respondent in the court of appeals proceedings.

Respondents other than FERC participated in the proceedings before FERC and were, as designated below, petitioners and/or intervenors in the court of appeals proceedings:

Petitioners:

California Public Utilities Commission

City of Seattle, Washington

City of Tacoma, Washington

People of the State of California *ex rel.* Edmund G. Brown, Jr. (replacing Bill Lockyer), Attorney General

Port of Seattle, Washington

Intervenors:

Alcoa Inc.

Arizona Public Service Company

Bonneville Power Administration

BP Energy Company

California Electricity Oversight Board

California Independent System Operator Corporation

California Public Utilities Commission

City of Los Angeles Department of Water and Power

City of Redding, California

City of Santa Clara, California

City of Seattle, Washington

City of Tacoma, Washington

Columbia Falls Aluminum Company, LLC

Duke Energy North America, LLC

Duke Energy Trading and Marketing, LLC

El Paso Marketing, LP (f/k/a El Paso Merchant Energy, LP)

M-S-R Public Power Agency

Modesto Irrigation District

Northern California Power Agency

PacifiCorp

People of the State of California *ex rel.* Edmund G. Brown, Jr. (replacing Bill Lockyer), Attorney General

Pinnacle West Capital Corporation

Port of Seattle, Washington

PPL EnergyPlus, LLC

PPL Montana, LLC

Public Service Company of Colorado

Public Service Company of New Mexico

Public Utility District No. 1 of Benton County, Washington

Public Utility District No. 1 of Franklin County, Washington

Public Utility District No. 2 of Grant County, Washington

Public Utility District No. 1 of Grays Harbor County, Washington

Southern California Edison Company

Tractebel Energy Marketing Inc.

Williams Power Company, Inc.

CORPORATE DISCLOSURE STATEMENTS

Pursuant to Rule 29.6 of the Rules of this Court, Petitioners Puget Sound Energy, Inc., Avista Corporation, Avista Energy, Inc., Constellation Energy Commodities Group, Inc. (f/k/a Constellation Power Source, Inc.), IDACORP Energy L.P., Morgan Stanley Capital Group Inc., Portland General Electric Company, Powerex Corp., PPL EnergyPlus, LLC, PPL Montana, LLC, Sempra Energy Trading LLC (f/k/a Sempra Energy Trading Corp.), Shell Energy North America (US), L.P. (f/k/a Coral Power, L.L.C.), and TransCanada Energy Ltd. state the following:

Puget Sound Energy, Inc. ("Puget") is organized under the laws of the State of Washington and is headquartered in Bellevue, Washington. Puget's principal office is located at 10885 NE 4th Street, Bellevue, Washington 98004. Puget provides electric and natural gas service to retail customers in a 6,000-square-mile area principally in the Puget Sound region within the State of Washington. Since February 6, 2009, Puget is an indirect, wholly owned subsidiary of Puget Holdings LLC, a consortium of investors led by Macquarie Infrastructure Partners I, Macquarie Capital Group Limited, the Canada Pension Plan Investment Board, and British Columbia Investment Management Corporation, and also includes Alberta Investment Management, Macquarie-FSS Infrastructure Trust, and Macquarie Infrastructure Partners II. None of these entities is publicly traded or has issued shares to the public, and no publicly held corporation owns 10% or more of the stock of Puget.

Avista Corporation is a corporation organized under the laws of the State of Washington with its principal office in Spokane, Washington. Avista Cor-

poration is an investor-owned, publicly traded natural gas and electric utility engaged in, among other things, the businesses of: (1) distributing natural gas for residential, commercial, and industrial use; and (2) generating, transmitting, and distributing electric power to wholesale and retail customers and transmitting electric power on behalf of third parties. Avista Corporation operates its regulated utility business under the trade name "Avista Utilities." Avista Corporation has no parent companies. No publicly held company owns 10% or more of Avista Corporation stock.

Avista Energy, Inc. is a wholly owned subsidiary of Avista Capital, Inc., which in turn is a wholly owned subsidiary of Avista Corporation. Avista Corporation is a diversified energy company that is publicly held. No publicly held corporation other than Avista Corporation owns 10% or more of the stock of Avista Energy, Inc.

Constellation Energy Commodities Group, Inc. (f/k/a Constellation Power Source, Inc.), through the undersigned counsel, hereby certifies upon information and belief that Constellation Energy Commodities Group, Inc. is an indirect, wholly owned subsidiary of Constellation Energy Group, Inc., a publicly traded company, and that no publicly held company holds 10% or more of Constellation Energy Group, Inc.'s stock. Constellation Energy Commodities Group, Inc. is an energy marketing company that operates throughout North America under a market-based rate schedule originally approved by the Federal Energy Regulatory Commission on May 15, 1997, in Docket No. ER97-2261-000. (On November 1, 2004, Constellation Power Source, Inc. changed its name to Constellation Energy

Commodities Group, Inc. ("CCG"). On November 23, 2004, CCG filed a Notice of Succession in Docket No. ER05-261-000 informing the Commission of the name change. On January 6, 2005, the Commission accepted CCG's Notice of Succession. (*See* Unpublished Letter Order, Docket No. ER05-261-000, Issued January 6, 2005).)

IDACORP Energy L.P. ("IE") is a limited partnership organized under the laws of the State of Delaware. During a portion of the period subject to the orders on review, it was engaged in the business of purchasing and reselling power and providing scheduling services. IE also is successor-in-interest to the power marketing contracts of Idaho Power Company d/b/a IDACORP Energy. Idaho Power Company ("IPC") is a corporation organized under the laws of the State of Idaho. Until IE succeeded to IPC's power marketing business, IPC was engaged in the business of purchasing and reselling power and providing scheduling services, in addition to its utility business. IPC remains engaged in the latter. IDACORP Energy Services Company, a Nevada corporation, holds 99% of the partnership interests in IE, and IDACORP, Inc. holds 1% of the partnership interests in IE. IPC and IDACORP Energy Services Company are wholly owned subsidiaries of IDACORP, Inc., a publicly traded Idaho corporation.

Morgan Stanley Capital Group Inc. states that its parent company is Morgan Stanley. Morgan Stanley is a publicly held corporation that has no parent corporation. Based on Securities and Exchange Commission Rules regarding beneficial ownership, State Street Bank & Trust Company ("State Street"), 225 Franklin Street, Boston, Massachusetts 02110, beneficially owned 13.4% of Morgan Stanley's

stock (based on the Schedule 13G filed February 17, 2009, by State Street, acting in various fiduciary capacities). As of May 22, 2009, Mitsubishi UFJ Financial Group, Inc. ("MUFG"), 7-1 Marunouchi 2-chome, Chiyoda-ku, Tokyo 100-8330, beneficially owned 339,839,033 shares of Common Stock, representing approximately 21.47% of the outstanding shares of Common Stock of the Company (assuming full conversion of all of the shares of Series B Preferred Stock held by MUFG at the Initial Conversion Price and further assuming no conversion of any other securities not beneficially owned by MUFG that are convertible or exchangeable into shares of Common Stock) (based on the Schedule 13D filed on October 23, 2008, as amended by the first amendment thereto, filed on October 30, 2008, and as further amended by the second amendment thereto, filed on May 22, 2009 (together, the "MUFG Schedule 13D")). Capitalized terms used and not defined in this description shall have the meanings set forth in the MUFG Schedule 13D.

Portland General Electric Company is an Oregon corporation with its principal place of business at One World Trade Center, 121 SW Salmon Street, 17th Floor, Portland, Oregon 97204. No publicly held corporation owns 10% or more of PGE's issued and outstanding common stock.

Powerex Corp. is a Canadian corporation incorporated under British Columbia's Company Act. Powerex is wholly owned by the British Columbia Hydro and Power Authority, which is a Provincial Crown Corporation owned in its entirety by Her Majesty the Queen in right of the Province of British Columbia. No publicly held company owns any Powerex stock.

Sempra Energy Trading LLC ("SET") (f/k/a Sempra Energy Trading Corp.) is a limited liability company organized and existing under the laws of the State of Delaware. Its principal office is located at 58 Commerce Road, Stamford, Connecticut 06902. SET is a wholly owned subsidiary of RBS Sempra Commodities LLP ("RBS Sempra Commodities"), a UK limited liability partnership. RBS Sempra Commodities is owned by The Royal Bank of Scotland plc ("RBS"), which directly owns 51% of the voting interests, and Sempra Energy, which indirectly owns 49% of the voting interests. RBS is a wholly owned subsidiary of The Royal Bank of Scotland Group plc, a public limited company registered in Scotland. Sempra Energy is a publicly traded company. No other publicly held company has a 10% or greater ownership interest in SET.

Shell Energy North America (US), L.P. (f/k/a Coral Power, L.L.C.) is an indirect subsidiary of Shell Oil Company. Shell Oil Company is a wholly owned subsidiary of Shell Petroleum Inc. Shell Petroleum Inc. is a wholly owned subsidiary of Shell Petroleum N.V. Royal Dutch Shell plc, whose shares are publicly traded, owns 100% of Shell Petroleum N.V. The other parent companies of Shell Energy listed above are not publicly traded. No publicly held company has a 10% or greater ownership interest in Royal Dutch Shell plc.

TransCanada Energy Ltd. ("TCE") is a Canadian corporation, with its principal place of business in the City of Calgary, Alberta, Canada. TCE owns generating facilities that are located in Alberta, Canada, and sells capacity and energy from those facilities exclusively within Canada. TCE is an indirect, wholly owned subsidiary of TransCanada PipeLines

Limited, which in turn is a direct, wholly owned subsidiary of TransCanada Corporation, a holding company that was created under a plan of arrangement approved by the common shareholders of TransCanada PipeLines Limited on April 25, 2003, and subsequently by the Court of Queen's Bench of Alberta, Canada. Common shares in TransCanada Corporation are traded on the Toronto and New York stock exchanges. There is no publicly held company directly owning 10% or more of TCE.

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Puget Sound Energy, Inc. ("Puget") et al. respectfully petition for a writ of certiorari to review the U.S. Court of Appeals for the Ninth Circuit's judgment in this case.

INTRODUCTION

In a judgment of enormous practical significance for administrative law generally and as applied to multi-billion dollar litigation arising out of the 2000-2001 California energy crisis, the Ninth Circuit created multi-circuit conflicts on three questions of administrative law that routinely affect agency practice.

The first concerns when an agency's exercise of discretion to terminate pre-enforcement activities without taking enforcement action may be subject to judicial review. Reconstruing *Heckler v. Chaney*, 470 U.S. 821 (1985), the Ninth Circuit established a presumption *in favor of* judicial review whenever the agency "take[s] steps towards enforcing a violation of the law" that inform its decision whether to initiate an enforcement action. Pet. App. 18a. That innovation departs from the generally accepted presumption in other circuits *against* reviewability in those circumstances.

The *Heckler* principle serves important interests: affording federal agencies flexibility over their decisions whether to enforce; and assuring targets of preliminary agency investigations that termination offers an end to their legal jeopardy. Left uncorrected, the Ninth Circuit's approach threatens to expand significantly the domain of judicial review of discretionary agency decisions not to enforce. Moreover, the Ninth Circuit's novel assertion of judicial review of preliminary agency action here directly negates Congress's command that the Federal Energy Regulatory Commission ("FERC") promptly resolve cases

arising out of the California energy crisis and reopens a closed administrative proceeding in which FERC had decided that the equities weighed against initiating an enforcement proceeding for Pacific Northwest ("PNW") transactions.

The Ninth Circuit then compounded its *Heckler* error in two ways: by failing to give appropriate deference to FERC's management of its own dockets and by rejecting FERC's interpretation of petitioner Puget's administrative complaint. The court ordered FERC to consider allegations of tariff violations on remand, notwithstanding that FERC had already investigated those allegations in separate, FERC-initiated proceedings. The court's decision to override FERC's discretionary judgment to address distinct issues in different proceedings conflicts with other circuits' approach.

The court similarly disregarded FERC's construction of Puget's complaint, which had sought only price caps for wholesale electricity sales to serve PNW customers. Whereas FERC had construed the complaint to *exclude* transactions to serve California customers, the Ninth Circuit (in conflict with other circuits' approach) read the complaint to include electricity sales to the California Department of Water Resources ("CDWR") to serve Californians that occurred months after Puget filed its complaint.

The Ninth Circuit's novel interpretations of established administrative law principles transform a decade-old proceeding about price caps for PNW electricity purchases into a new case seeking billions in refunds for California transactions without any contemporaneous notice to sellers.

OPINIONS BELOW

The court of appeals' opinion (Pet. App. 1a-37a) is reported at 499 F.3d 1016. FERC's orders (Pet. App. 38a-110a, 111a-377a, 378a-408a, 409a-447a, 448a-453a) are reported at 96 FERC ¶ 61,120, 96 FERC ¶ 63,044, 103 FERC ¶ 61,348, 105 FERC ¶ 61,183, and 106 FERC ¶ 61,109.

JURISDICTION

The court of appeals entered its judgment on August 24, 2007. Petitions for rehearing were denied on April 9, 2009. *See* Pet. App. 454a. On June 29, 2009, Justice Kennedy extended the time for filing a certiorari petition to and including September 4, 2009. *See id.* at 465a. This Court's jurisdiction is invoked under 28 U.S.C. § 1254(1).

STATUTORY PROVISIONS INVOLVED

Relevant provisions of the Federal Power Act ("FPA"), 16 U.S.C. §§ 791a *et seq.*, are set forth at Pet. App. 455a-464a.

STATEMENT OF THE CASE

1. Statutory Background

The FPA charges FERC with ensuring that interstate electricity rates are "just and reasonable." 16 U.S.C. § 824d(a). FPA § 206 authorizes FERC to conduct a hearing "upon its own motion or upon complaint" to determine whether an effective rate is unlawful. *Id.* § 824e(a). If FERC chooses to hold a hearing under § 206, it "shall specify the issues to be adjudicated" and, if "after [such] hearing" it "find[s] that any rate" is "unjust [or] unreasonable," FERC "shall determine" and "fix" "the just and reasonable rate." *Id.*

Section 206 also authorizes FERC to exercise discretion in providing refunds for unlawful rates. *See*

id. § 824e(b). FERC can only order refunds for a period after the "refund effective date," which the applicable FPA provision required to be at least 60 days after the filing of a complaint or publication of FERC's decision to initiate a proceeding. *See id.* § 824e(b) (2000).

2. The California Energy Crisis and FERC's Proceedings

a. This Court and others have documented the events leading up to the energy crisis in California and other western U.S. markets in 2000-2001. *See, e.g., Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish County*, 128 S. Ct. 2733, 2742-43 (2008); *Public Utils. Comm'n v. FERC*, 462 F.3d 1027, 1037-42 (9th Cir. 2006) ("*PUC*").

In mid-2000, the price of electricity in the California electricity market "jumped dramatically" because of "a combination of natural, economic, and regulatory factors." *Morgan Stanley*, 128 S. Ct. at 2742 (internal quotations omitted). California experienced disruptive "blackouts, brownouts, and system emergencies." *PUC*, 462 F.3d at 1040 (footnote omitted).

b. This case concerns the distinct but related market for electricity in the Pacific Northwest – Oregon, Washington, Idaho, and parts of Montana, Nevada, Utah, and Wyoming. *See* 16 U.S.C. § 839a(14). Unlike California's centralized exchanges, the PNW market operates primarily through bilateral contracts. *See* Pet. App. 9a, 394a. The PNW wholesale power market is one of the nation's most liquid – "electricity in the region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain." *Id.* at 398a-399a.

PNW utilities generally sell power south, into California, during the summer months, when demand

there is high and PNW hydroelectric generation conditions are favorable. *See id.* at 311a. In the winter months, PNW utilities generally import power, particularly from California, "to supplement local supplies during winter cold spells" when generation conditions are unfavorable and local heating demand is high. *Id.*

In 2000, PNW energy prices "rose dramatically." *Id.* at 391a (internal quotations omitted). The increases were driven in part by "supply and demand fundamentals," *id.*, such as unusually unfavorable winter weather, *see id.* at 314a-315a, and by ongoing California market dysfunctions, *see id.* at 8a-9a, 391a.

c. On October 26, 2000, petitioner Puget – the sole complainant before FERC – filed a § 206 complaint. *See* C.A. J.E.R. 2-16. Puget sought "a price cap for wholesale sales of energy and capacity" into the PNW "equal to the lowest cap on prices," if any, FERC established in response to a prior request by San Diego Gas & Electric Co. ("SDG&E") for price caps in California. *Id.* at 13; *see also id.* at 3-4, 14-15. Puget – an investor-owned utility serving retail customers in Washington State – feared being subjected to "uncapped prices when [it] need[ed] [to buy] power" from California in the winter, but receiving only capped California prices when selling power south in the summer. *Id.* at 12. Puget sought to avoid having to sell low and buy high, whipsawed by price caps applicable to California but not the PNW. *See id.* Puget expressly disclaimed interest in refunds and sought "prospective only" relief. *Id.* at 13.

On December 15, 2000, FERC dismissed Puget's complaint, "declin[ing] to implement a region-wide price cap" or to initiate a § 206 hearing. *See San*

Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs., 93 FERC ¶ 61,294, at 62,019 (2000). Puget sought rehearing of FERC's dismissal of its complaint "to the extent the order declines to impose a price cap" in the PNW. C.A. J.E.R. 86.

On April 26, 2001, however, FERC imposed a price cap in California markets. *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 95 FERC ¶ 61,115, at 61,353-65 (2001). And, on June 19, 2001, FERC extended that price cap to the PNW. *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 95 FERC ¶ 61,418, at 62,567-70 (2001).

On June 22, 2001, Puget moved to withdraw its rehearing request and to dismiss its complaint. *See* C.A. J.E.R. 97-102. Puget explained that FERC's "June 19 Order satisfie[d] Puget Sound's Complaint because it implement[ed] price" caps in the PNW that matched those in California – the very remedy Puget had requested. *Id.* at 100. Several parties – including parties that had not previously (or timely) sought to intervene – opposed Puget's motion. *See* Pet. App. 12a-13a; C.A. J.E.R. 103-04. Those parties for the first time "sought to expand the complaint proceeding and the requested remedy" to include "retroactive refunds for spot market bilateral sales in the Pacific Northwest." Pet. App. 378a-379a; *see* C.A. J.E.R. 104.

In July 2001, FERC decided on its own motion to "establish[] another proceeding . . . to explore whether there may have been unjust and unreasonable charges . . . in the Pacific Northwest . . . and the calculation of any refunds associated with such charges." Pet. App. 39a. FERC "establish[ed] a separate preliminary evidentiary proceeding" before

an administrative law judge ("ALJ") to "help the Commission to determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest," to "assist[] the Commission in understanding the Pacific Northwest spot market and the proper action to be taken," and to "encourage the parties to try to settle past accounts." *Id.* at 102a-103a, 390a.

In short, FERC "desired additional information before making a decision" whether to initiate § 206 hearings that could lead to refunds. *Id.* at 425a. FERC expressly declined to set a refund effective date under § 206, explaining it had not yet revised its "previous determination not to set [Puget's] complaint for hearing." *Id.* at 102a n.75; *see* 16 U.S.C. § 824e(b); Pet. App. 382a (FERC "did not set the complaint for hearing under FPA Section 206 or establish a refund effective date in the July 25 Order").

In recommendations and findings (*see* Pet. App. 111a), the ALJ first determined that purchases by the California Energy Resources Scheduling division ("CERS") of CDWR fell outside the scope of Puget's complaint, which initiated – and therefore defined – the proceeding's scope.[1] *See id.* at 209a-210a. The ALJ reasoned that CDWR's transactions were "not to a PNW load server," but instead served California end-user customers, while "Puget's complaint specifically referred" to sales serving PNW load. *Id.* at 209a, 371-372a.

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[1] In January 2001, the California legislature created CERS because the state's retail utilities were "fast becoming insolvent." *PUC*, 462 F.3d at 1042. CDWR, through CERS, made bulk power purchases worth more than $5 billion for California consumers. *See id.*

The ALJ next recommended that the Commission not initiate a § 206 proceeding. *First*, the evidence failed to establish that prices were unjust or unreasonable. *See id.* at 326a. *Second*, a refund proceeding would prove unworkable because it would entail recalculating hundreds of thousands of transactions. *See id.* at 369a-370a.

On December 19, 2002, following the public disclosure of evidence suggesting that Enron had manipulated energy prices in California, FERC allowed the parties "to submit 'additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001 and propose[] new and/or modified findings of fact.'" *Id.* at 14a (quoting C.A. J.E.R. 526).

On June 25, 2003, FERC terminated this proceeding. Citing *Heckler v. Chaney*, FERC decided in its discretion not to pursue a § 206 enforcement action for PNW transactions. *See id.* at 402a & n.64. "Based on the totality of the circumstances," FERC concluded that, "even if" a § 206 hearing were to conclude that "prices were unjust and unreasonable," FERC would not order sellers to pay refunds, because such refunds "would not result in an equitable resolution of the matter." *Id.* at 401a-402a.[2]

FERC's conclusion rested on several equitable factors. *See id.* at 392a-402a. FERC relied on the ALJ's factual findings that "electricity in the region is traded an average of six times" before being consumed, and that "approximately 500,000 transactions

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[2] The same day it terminated the PNW proceeding, FERC issued separate orders opening new proceedings to investigate and redress alleged market manipulation and tariff violations in both California and the PNW. *See infra* p. 24.

would have to be recalculated if refunds are required." *Id.* at 398a-399a. FERC concluded that "an immense number of transactions [would be] subject to refund in th[e] case," requiring "prolonged time and effort to unravel" and making it, "in many instances," "nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision." *Id.* (internal quotations omitted).

Even if the "practical difficulty of determining the chain[] of transactions" could be overcome, FERC further observed that "[a] large portion of the power bought and sold in the Pacific Northwest is by governmental entities" over which FERC "lack[ed] authority to impose refund obligations," *id.* at 394a-395a, 400a, and that "there will be few chains of transactions that will not contain a non-jurisdictional transaction," *id.* at 400a. Consequently, "the burden of paying refunds will fall on a limited class of jurisdictional sellers," while the government entities involved in numerous transaction chains could "receive refunds for their high-priced purchases while they are exempt from providing refunds for any high priced sales they may have made." *Id.* at 395a (internal quotations omitted). "Such an outcome," FERC determined, "is not equitable." *Id.* at 400a.

Finally, FERC reasoned that awarding refunds would "unfairly punish[]" utilities that "prudently engaged in a procurement strategy" that relied on long-term rather than spot market transactions and would "undermine the credibility of the regulatory process and could jeopardize investment in energy infrastructure." *Id.* at 397a-398a (internal quotations omitted).

On rehearing, FERC reaffirmed that "[t]he time and resources that must be devoted to refund cal-

culations is a legitimate consideration within the Commission's discretion," *id.* at 442a, and that "refunds are not appropriate because such relief would arbitrarily remedy only a portion of the regional market," *id.* at 436a. FERC noted that, "[i]n reaching its decision," it "considered the complete record, including the material submitted in the [additional] filings" alleging market manipulation. *Id.* at 419a.

FERC also adopted ALJ findings that CDWR's transactions were outside Puget's complaint. *See id.* at 432a n.43. On further rehearing, FERC reaffirmed its understanding that sales to CDWR were outside the complaint's scope because they were not transacted to "serv[e] load in the Pacific Northwest but [instead to] serv[e] California load." *Id.* at 452a-453a.

3. The Decision Below

The court of appeals granted the petitions for review in part and remanded for further Commission proceedings.

The court first held that FERC's decision not to initiate a § 206 enforcement proceeding for the PNW was reviewable under the Administrative Procedure Act ("APA"). *See* 5 U.S.C. § 701(a)(2). The court rejected FERC's argument that the agency's decision not to enforce § 206 was committed by law to its discretion. *See* Pet. App. 17a-19a. The court reasoned that "*Heckler* limited the presumption of unreviewability to 'agency *refusals to institute* investigative or enforcement proceedings.'" *Id.* at 18a (quoting *Heckler*, 470 U.S. at 838). Under the court's test, once an agency has "take[n] steps towards enforcing a violation of the law, the outcome it chooses is subject to judicial review." *Id.* Because FERC "made a decision to commit resources to an examination of whether

refunds are warranted," "held hearings," and "t[ook] evidence," the court deemed that decision reviewable. *Id.* at 18a-19a.

Although the court "decline[d] to reach the merits of FERC's ultimate decision to deny refunds," *id.* at 36a, it remanded for further proceedings in light of two other rulings. *First*, the court reversed FERC's interpretation of Puget's complaint, holding that "Puget's complaint provides no indication of an intent to exclude refunds for energy purchased in the Pacific Northwest spot market for consumption outside the geographical area." *Id.* at 31a.

Second, the court held that FERC failed adequately to consider evidence of market manipulation. *See id.* at 33a-36a. The court remanded for FERC to consider that evidence "in detail" and to "account for it in any future orders regarding the award or denial of refunds in the Pacific Northwest proceeding." *Id.* at 36a.[3]

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[3] Several petitioners, such as Puget, IDACORP, Morgan Stanley Capital Group, and Portland General, have reached settlements with CDWR and respondent California, which release, among other things, claims from CDWR relating to transactions at issue here. Some respondents, such as Port of Seattle and City of Seattle, which were petitioners below, are not parties to those settlements. Despite those settlements, the Ninth Circuit's decision exposes these petitioners to potential refund claims for sales to utilities that resold the power (directly or indirectly) to CDWR.

REASONS FOR GRANTING THE PETITION

I. THE NINTH CIRCUIT ERRONEOUSLY HELD – IN CONFLICT WITH FOUR OTHER CIRCUITS – THAT PRELIMINARY FACT-FINDING TO INFORM A DECISION COMMITTED TO AGENCY DISCRETION RENDERS THAT DECISION REVIEWABLE

APA § 701(a)(2) bars judicial review of "agency action[s] . . . committed to agency discretion by law." 5 U.S.C. § 701(a)(2). In *Heckler*, this Court held that § 701(a)(2) creates a "presumption" that an "agency's decision not to undertake certain enforcement actions" is unreviewable. 470 U.S. at 831. The Ninth Circuit held that *Heckler*'s presumption of unreviewability does not apply whenever an agency "take[s] steps towards enforcing a violation of the law" even if the agency, after gathering information to inform its discretion, chooses not to pursue enforcement. Pet. App. 18a. That judgment cannot be squared with other circuits' holdings that agencies may utilize investigative proceedings to inform their exercises of discretion without rendering those decisions reviewable. The Ninth Circuit's misunderstanding of *Heckler* led to error in a case with tremendous practical consequences for resolving the multi-billion dollar California energy crisis litigation.

A. The Decision Below Conflicts With Other Circuits' Interpretation Of *Heckler*'s "Presumptively Unreviewable" Standard

1. *Heckler* held that "an agency's decision not to prosecute or enforce, whether through civil or criminal process, is a decision generally committed to an agency's absolute discretion." 470 U.S. at 831; *see* 5 U.S.C. § 701(a)(2). Such decisions are "general[ly] unsuitab[le] for judicial review" because they "often

involve[] a complicated balancing of a number of factors which are peculiarly within [the agency's] expertise." *Heckler*, 470 U.S. at 831. More particularly, "review is not to be had if [a] statute is drawn so that a court would have no meaningful standard against which to judge the agency's exercise of discretion." *Id.* at 830.

2. Four circuits interpret *Heckler* to hold that agency non-enforcement decisions do not become reviewable simply because the agency has taken investigative or pre-enforcement steps to inform its decision. *See Schering Corp. v. Heckler*, 779 F.2d 683, 685-87 (D.C. Cir. 1985); *New York State Dep't of Law v. FCC*, 984 F.2d 1209, 1213-15 (D.C. Cir. 1993); *Baltimore Gas & Elec. Co. v. FERC*, 252 F.3d 456, 459-60 (D.C. Cir. 2001); *Greer v. Chao*, 492 F.3d 962, 966-67 (8th Cir. 2007) (O'Connor, J., sitting by designation); *Sierra Club v. Larson*, 882 F.2d 128, 131-33 (4th Cir. 1989); *Sherman v. Black*, 315 F. App'x 347, 349 (2d Cir. 2009). By contrast, the Ninth Circuit's conflicting standard posits that such "steps towards enforcing a violation of the law" render "the outcome [the agency] chooses . . . subject to judicial review." Pet. App. 18a. This Court should resolve the circuits' disagreement over *Heckler*'s proper scope.

D.C. Circuit. The D.C. Circuit has consistently held that agency decisions to settle rather than to pursue enforcement actions – *i.e.*, opting not to proceed with enforcement after some investigation or pre-enforcement analysis has already occurred – fall within the scope of *Heckler*'s presumptive unreviewability.[4]

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[4] For both settlements and decisions not to enforce, the agency chooses not to exercise its statutory enforcement authority

In *New York State Department of Law v. FCC*, for example, the D.C. Circuit held that *Heckler*'s presumption of unreviewability applied to "an agency's decision to settle or dismiss an enforcement action." 984 F.2d at 1214. The Federal Communications Commission ("FCC") had issued a "show cause" order after learning of possible Communications Act violations through a routine audit. *See id.* at 1211-12. After several months of investigation and negotiation, the FCC and the carriers entered into a consent decree under which the FCC agreed not to bring a formal enforcement action. *See id.* at 1212. Several intervenors contested the FCC's decision to terminate the proceeding.

In rejecting the intervenors' challenge, the D.C. Circuit observed that "the FCC is best positioned to weigh the benefits of pursuing an adjudication against the costs to the agency (including financial and opportunity costs) and the likelihood of success." *Id.* at 1213. The court concluded that those same discretionary considerations informed both "the discretionary decision to initiate an action" and "the . . . decision to settle the enforcement action." *Id.* at 1214. The governing statute in neither situation restricted the agency's discretion. *See id.* at 1215 ("Certainly the statute does not lay out any circumstances in which the agency is required to undertake *or to continue* an enforcement action.") (emphasis added).

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after gathering information to inform that discretionary choice. The agency may determine that *some* remedy short of what it could obtain through enforcement utilizes agency resources most effectively. FERC below reasoned in part that imposition of the region-wide price cap provided "appropriate relief." Pet. App. 379a.

The D.C. Circuit reiterated that holding in *Baltimore Gas & Electric*, concluding that FERC's decision to settle rather than to bring an enforcement action following an investigation was "committed to the agency's nonreviewable discretion." 252 F.3d at 457. FERC had reason to believe that a natural gas vendor had violated the Natural Gas Act ("NGA"), 15 U.S.C. § 717f(c), by abandoning capacity in its natural gas lines. FERC initiated an "investigation into whether [the vendor] had unlawfully abandoned service without first obtaining FERC approval." 252 F.3d at 457. That investigation proceeded for four years before FERC decided to settle without determining whether a violation had occurred. *See id.*

A customer of the vendor then challenged the settlement. The D.C. Circuit observed that *Heckler* "sets forth the general rule that an agency's decision not to exercise its enforcement authority, *or to exercise it in a particular way*, is committed to its absolute discretion." *Id.* at 459 (emphasis added). The court reasoned that "FERC's decision to settle . . . , and its consequent decision not to see its enforcement action through to fruition, is a paradigmatic instance of an agency exercising its presumptively nonreviewable enforcement discretion." *Id.* at 460.

The D.C. Circuit adheres to that approach. *See Association of Irritated Residents v. EPA*, 494 F.3d 1027, 1035 (D.C. Cir. 2007).

Eighth Circuit. In *Greer v. Chao*, the Eighth Circuit held that "the manner in which an agency opts to investigate a complaint is largely a matter left to the agency's discretion." 492 F.3d at 965. The agency there decided – after an 18-month investigation – not to pursue enforcement of an individual's administrative complaint. *See id.* at 963. Although the indi-

vidual challenged "the Secretary's failure to investigate certain aspects of his larger complaint," the court reasoned that "at bottom [the complainant] objects to the Secretary's decision not to initiate enforcement proceedings." *Id.* at 966. Accordingly, the fact and content of the agency's investigation did not remove its discretionary enforcement decision from *Heckler*'s presumption of unreviewability: "[d]eciding which claims are facially without merit, which claims merit investigation, and the level of investigation desirable, all are enforcement-related decisions," and are not subject to review. *Id.* at 965 (internal quotations omitted).

Fourth Circuit. In *Sierra Club v. Larson*, the Fourth Circuit similarly held that an agency's decision not to initiate an enforcement proceeding – after conducting "a fact-finding investigation" and producing a "report" recommending "corrective steps" short of enforcement – remained unreviewable. 882 F.2d at 130. The court concluded that the investigation and report were not themselves reviewable, *see id.* at 132, and that those steps did not open to review the agency's decision not to prosecute. The court concluded that "the agency exercised its discretion, after an investigation, by declining to proceed any further." *Id.*

Second Circuit. Finally, the Second Circuit concluded in *Sherman v. Black* that an agency decision not to enforce after an investigation was unreviewable. *See* 315 F. App'x at 349 ("[The agency] reviewed the evidence, discussed the circumstances alleged in [the] complaint, and determined that [the] allegations did not warrant further action.").

3. The Ninth Circuit below articulated a conflicting legal standard to justify judicial review of FERC's

decision not to enforce § 206, following a pre-enforcement, preliminary fact-finding proceeding. The court's standard authorizes judicial review of agency pre-enforcement actions where the agency has taken "steps towards enforcing a violation of the law" and has "made a decision to commit resources to an examination of whether" enforcement proceedings should be initiated. Pet. App. 18a.

Yet those very same steps had been taken in the other circuits' cases described above. The FCC issued a "show cause" order and conducted discovery in *New York State Department of Law*, 984 F.2d at 1211-12; FERC conducted a four-year investigation into potential wrongdoing in *Baltimore Gas & Electric*, 252 F.3d at 457; and the agencies in *Greer*, *Sierra Club*, and *Sherman* each launched "investigation[s]" in which complaining parties participated and were given opportunities to respond. 492 F.3d at 963; 882 F.2d at 130; 315 F. App'x at 349. This case, therefore, would have been decided differently if considered by one of those circuits.

B. Preliminary Fact-finding Does Not Render Decisions Committed By Law To Agency Discretion Reviewable Under The APA

The Ninth Circuit's rule finds no support in APA § 701(a)(2) or this Court's interpretation of that statute in *Heckler* and its progeny. The touchstone of reviewability is congressional intent: "If [Congress] has indicated an intent to circumscribe agency enforcement discretion, and has provided meaningful standards for defining the limits of that discretion, there is 'law to apply' under § 701(a)(2)"; "if it has not, then an agency refusal to institute proceedings is a decision 'committed to agency discretion by law.'" *Heckler*, 470 U.S. at 834-35. Generally, whether

Congress has provided meaningful standards for judicial review of an agency decision not to prosecute is a question of statutory interpretation independent of the agency's procedures in making that decision.

Similarly, the three reasons why this Court found "judicial review of agency decisions to refuse enforcement" to be "general[ly] unsuitab[le]" apply regardless of whether the agency has taken steps toward exercising its enforcement discretion. *First*, "an agency decision not to enforce often involves a complicated balancing" of factors relating to the proper use of the agency's resources: "the agency must not only assess whether a violation has occurred, but whether agency resources are best spent on this violation or another, whether the agency is likely to succeed if it acts, whether the particular enforcement action requested best fits the agency's overall policies, and, indeed, whether the agency has enough resources to undertake the action at all." *Id.* at 831. An agency's preliminary inquiry to inform its enforcement discretion does not change the nature of that calculus.

Second, "when an agency refuses to act it generally does not exercise its *coercive* power over an individual's liberty or property rights." *Id.* That observation holds regardless of whether the agency first conducts investigatory proceedings.

Third, the Court's analogy to prosecutorial discretion, *see id.*, extends to agencies' pre-enforcement investigative activities. Just as a prosecutor may consider evidence before declining to indict, so too may an agency investigate facts before declining to enforce a statute.

C. The Ninth Circuit Erroneously Found FERC's Decision Not To Pursue Enforcement Under § 206 To Be Reviewable

After granting all the relief Puget sought in its complaint, FERC acted "upon its own motion," 16 U.S.C. § 824e(a), to explore whether to award refunds for PNW electricity sales during the energy crisis. FERC held a "separate preliminary evidentiary proceeding," Pet. App. 102a, to gather "additional information before making a decision" whether to initiate a hearing under § 206, *id.* at 425a. From that information, FERC decided not to set the matter for hearing under § 206 and to cease enforcement activities. That decision is not reviewable.

In holding otherwise, the Ninth Circuit did not analyze § 206's terms as *Heckler* requires. Instead, the court erroneously held that, because the Commission "ha[d] already made a decision to commit resources to an examination of whether refunds [were] warranted," any decision resulting from that examination was reviewable. *Id.* at 18a.

The FPA grants FERC unfettered discretion to decide whether to take enforcement action on its own motion under § 206. That section does not address *when* or *why* the Commission should hold a "hearing"; rather, it provides that, "*[w]henever* the Commission, after a hearing held upon its own motion . . . , shall find that any rate . . . is unjust [or] unreasonable, . . . the Commission shall determine the just and reasonable rate." 16 U.S.C. § 824e(a) (emphasis added). The statute specifies what a "motion of the Commission to initiate a proceeding" must contain, *id.*; requires FERC, "*[i]f* . . . [it] shall decide to hold a hearing," to "fix by order the time and place of such hearing and [to] specify the issues to be adjudicated,"

id. (emphasis added); and requires FERC, "*[w]henever* [it] institutes a proceeding," to "establish a refund effective date," *id.* § 824e(b) (emphasis added). Those provisions constrain FERC's discretion *after* it initiates a hearing on its own motion under § 206, without restricting its discretion to conduct preliminary fact-finding investigations to inform its decision.

Nor does the FPA constrain FERC's exercise of its fact-finding powers. FPA § 307 provides that "[t]he Commission *may* investigate any facts . . . *which it may find necessary or proper* in order to determine whether" a FPA violation has occurred. 16 U.S.C. § 825f(a) (emphases added). And § 309 authorizes FERC "to perform any and all acts . . . necessary or appropriate to carry out the provisions of this chapter." *Id.* § 825h. "[A]n administrative agency's decision to conduct or not to conduct an investigation is committed to the agency's discretion." *General Motors Corp. v. FERC*, 613 F.2d 939, 944 (D.C. Cir. 1979) (per curiam).

As in *Heckler*, "[t]he Act's enforcement provisions . . . commit complete discretion to the [agency] to decide how and when they should be exercised." 470 U.S. at 835. Absent any statutory guidance suggesting how, when, or why FERC should act to enforce § 206 on its own motion, there is "no law to apply." *Id.* at 830-31 (internal quotations omitted).

FERC made an unreviewable decision not to "initiate a proceeding" under § 206 that could lead to refunds for PNW sales. 16 U.S.C. § 824e(b). It repeatedly reaffirmed that it did not set Puget's complaint for a hearing, *see* Pet. App. 382a, 417a,[5] and did not

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[5] FERC initially dismissed Puget's complaint without setting it for a hearing, and Puget's complaint remained dismissed dur-

issue an order "fix[ing] . . . the time and place of such hearing and . . . specify[ing] the issues to be adjudicated," *see id.* at 102a-103a. FERC did not set a "refund effective date" as § 206 requires "[w]henever the Commission institutes a proceeding under this section." 16 U.S.C. § 824e(b); *see* Pet. App. 102a n.75, 382a, 417a, 424a n.26.

The Ninth Circuit below erroneously relied on *MCI Telecommunications Corp. v. FCC*, 917 F.2d 30 (D.C. Cir. 1990), as authority for judicial review of an agency's decision to terminate an enforcement action once begun. There, the FCC "set the [challenged] tariffs for a hearing" under 47 U.S.C. § 204, a statute similar to FPA § 206. *MCI*, 917 F.2d at 33. The FCC had designated certain questions for inquiry – just as FERC would have been required to do had it initiated a § 206 hearing in this case – and later abandoned those questions after having taken evidence and arguments. *See id.* at 41-42. The D.C. Circuit there held that the FCC had initiated an enforcement action and needed to provide a reasoned explanation for its subsequent decision not to reach certain issues. *See id.* at 42. Here, by contrast, FERC never initiated an enforcement action under FPA § 206.[6]

Finally, FERC's decision not to initiate a § 206 proceeding for the PNW is plainly "unsuitab[le]" for review under *Heckler*. 470 U.S. at 831. FERC's assessment that the equities weighed against refunds,

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ing the Commission's separate preliminary evidentiary proceeding. *See* Pet. App. 417a.

[6] The Ninth Circuit opined that it "regularly exercise[s] judicial review over FERC's decision to grant or deny refunds." Pet. App. 19a. But none of the decisions cited reviewed a determination not to hold a hearing under FPA § 206.

even assuming that rates were unjust or unreasonable, turned on the impracticability of determining who should get such refunds, the arbitrariness of refunds given FERC's lack of jurisdiction over many sellers, and the agency's conclusion that refunds would reward uneconomic behavior. *See* Pet. App. 390a-402a. Those considerations are "peculiarly within [the agency's] expertise." *Heckler*, 470 U.S. at 831.

D. The Proper Understanding Of *Heckler*'s "Presumptive Unreviewability" Standard Raises A Question Of Great Practical And Recurring Importance

Agencies routinely take steps to inform themselves before deciding whether to bring enforcement actions. By injecting the specter of judicial review into those steps, the Ninth Circuit's rule will have significant adverse consequences for both agency decision-making and those entities (like petitioners here) that cannot order their affairs in reliance on the agency's decision not to take any enforcement action against them. When an agency crosses the line etched by the Ninth Circuit in ways that traditionally have been unreviewable, companies accused erroneously of wrongdoing will face the lingering threat that judicial second-guessing will reopen the agency's decision not to take enforcement action. Subjecting non-enforcement decisions to full judicial review risks significant misallocations of resources as agencies attempt to ensure that their previously informal procedural mechanisms are now sufficiently detailed to survive judicial review. *Cf. Vermont Yankee Nuclear Power Corp. v. Natural Res. Def. Council, Inc.*, 435 U.S. 519, 525 (1978).

The court's holding that preliminary agency fact-finding can render decisions not to prosecute subject to judicial review creates significant new "uncertainty and disagreement" in an area in which clarity is essential. 3 Richard J. Pierce, *Administrative Law Treatise* § 17.7, at 1273 (4th ed. 2002). As one commentator notes, it is particularly "important" that judicial review of agency inaction be placed on a "solid basis" to provide agencies and their regulated entities with certainty. Eric Biber, *The Importance of Resource Allocation in Administrative Law*, 60 Admin. L. Rev. 1, 4-5 (2008). The Ninth Circuit dramatically expanded the scope of agency actions potentially subject to review and authorized courts to parse even more finely the fact-intensive question whether an agency has acted or declined to act within the meaning of *Heckler*, thereby adding to the scope of disagreement over the Court's seminal decision.

II. THE NINTH CIRCUIT IMPROPERLY INTERFERED WITH FERC'S ABILITY TO STRUCTURE ITS PROCEEDINGS IN CONFLICT WITH OTHER CIRCUITS' APPROACH

The Ninth Circuit further erred by remanding for FERC to consider allegations of tariff violations in the PNW proceeding, despite FERC's many "separate proceedings focusing on [the same allegations of] misconduct." Pet. App. 35a. That judgment impermissibly injected the court into FERC's management of its administrative dockets.

A. The Ninth Circuit Ordered FERC To Address Further In This Proceeding Factually Distinct Tariff Violation Allegations FERC Had Fully Considered In Separate Enforcement Proceedings

1. In deciding not to initiate a § 206 hearing concerning PNW transaction prices, FERC "considered the complete record" amassed through its preliminary evidentiary proceeding, "including the material" concerning alleged market manipulation. Pet. App. 419a. That decision rested on FERC's equitable determination that, *even if* prices in the PNW were unjust or unreasonable, awarding refunds would be impracticable, would necessarily result in arbitrariness due to FERC's lack of jurisdiction over many sellers, and would unfairly reward economically irrational behavior. *See supra* pp. 21-22. Allegations of market manipulation, even if proven true, were irrelevant to that conclusion.

The same day FERC declined to initiate a § 206 refund proceeding on its own motion in the PNW, it opened new proceedings specifically to investigate and redress alleged market manipulation and tariff violations in both California and the PNW. FERC ordered dozens of sellers "to show cause why their behavior . . . does not constitute gaming and/or anomalous market behavior" that violated relevant tariffs. *American Elec. Power Serv. Corp.*, 103 FERC ¶ 61,345, at 62,328 (2003); *see also Enron Power Mktg., Inc.*, 103 FERC ¶ 61,346, at 62,349 (2003) (same). FERC further ordered an ALJ to make findings from evidence "quantifying the full extent" of "unjust[] enrich[ment]" from such conduct and authorized the ALJ to recommend "disgorgement of unjust profits." *American Elec. Power*, 103 FERC at

62,328; *see also Enron Power Mktg.*, 103 FERC at 62,349 (same).

2. The Ninth Circuit recognized that "FERC already [was] addressing market manipulation in separate proceedings focusing on misconduct" – indeed, FERC earlier had completed those investigations – but it nonetheless held that FERC must consider such allegations in the PNW proceeding on remand. Pet. App. 35a-36a. In so doing, the court did not review the reasons FERC gave for not initiating a § 206 proceeding: "even if prices were unjust and unreasonable, it is not possible to fashion a remedy that would be equitable to all the participants in the Pacific Northwest market." *Id.* at 392a-393a. The court made no effort to explain how allegations of market manipulation, if proved, could alter FERC's balancing of equitable factors.[7] Instead, the court simply reapplied an earlier holding that also intruded on FERC's discretion to manage its dockets. *Id.* at 36a (citing *PUC*, 462 F.3d at 1048-51).

B. The Ninth Circuit Exceeded Its Authority In Holding That FERC Must Consider Evidence Of Tariff Violations In The PNW Docket

1. "An agency enjoys broad discretion in determining how best to handle related, yet discrete, issues in terms of procedures and priorities," and "need not solve every problem before it in the same proceeding." *Mobil Oil Exploration & Producing Southeast Inc. v. United Distrib. Cos.*, 498 U.S. 211, 230-31 (1991); *see also FPC v. Sunray DX Oil Co.*, 391 U.S.

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[7] The Ninth Circuit directed FERC to "reevaluate[]" three ALJ findings "in light of" the market manipulation evidence. Pet. App. 35a. None of those findings, however, underlay FERC's determination that the equities disfavored refunds.

9, 49-50 (1968). *Mobil Oil* held that FERC acted within its discretion in declining to consider the effect of certain contractual "take or pay" provisions in a rulemaking on gas delivery rates: "the agency could compile relevant data more effectively in a separate proceeding" and it had "taken steps to alleviate take-or-pay problems." 498 U.S. at 230 (internal quotations omitted). This Court concluded that it will not interfere in an agency's choice to pursue related "issue[s] separately" at least "where a different proceeding would generate more appropriate information and where the agency was addressing the question." *Id.*; *see also Sunray*, 391 U.S. at 49-50.

The D.C. Circuit has held consistently that an agency has "inherent power[] . . . to control its own docket." *GTE Serv. Corp. v. FCC*, 782 F.2d 263, 274 n.12 (D.C. Cir. 1986) (citing cases); *see City of Las Vegas v. Lujan*, 891 F.2d 927, 935 (D.C. Cir. 1989) (stating that "we would not strike down the [agency's decision] if it were a first step toward a complete solution, even if we thought [the agency] 'should' have covered both" issues in the same order) (footnote omitted); *see also, e.g., American Bird Conservancy, Inc. v. FCC*, 516 F.3d 1027, 1032 (D.C. Cir. 2008) (per curiam). Other circuits are in accord. *See, e.g., Aviators for Safe & Fairer Regulation, Inc. v. FAA*, 221 F.3d 222, 231 (1st Cir. 2000); *Cincinnati Bell Tel. Co. v. FCC*, 69 F.3d 752, 767 (6th Cir. 1995); *New Orleans Pub. Serv., Inc. v. FERC*, 659 F.2d 509, 516 (Former 5th Cir. Oct. 1981).

2. The Ninth Circuit's judgment conflicts with those cases by holding that FERC lacks discretion to determine that it can address an issue "more effectively in a separate proceeding." *Mobil Oil*, 498 U.S. at 230; *see* Pet. App. 35a-36a; *PUC*, 462 F.3d at 1049-

51. FERC's authority to regulate interstate power markets derives from at least two different FPA sections. Section 206 authorizes FERC review of rates to ensure they are "just and reasonable," and to order "only prospective[]" refunds. *Towns of Concord, Norwood & Wellesley v. FERC*, 955 F.2d 67, 72 (D.C. Cir. 1992). By contrast, FERC's authority to order remedies for tariff violations derives from FPA § 309, which authorizes FERC "to perform any and all acts . . . necessary or appropriate to carry out" the FPA. 16 U.S.C. § 825h. Remedies for tariff violations redress specific misconduct and necessarily are retrospective. *See Consolidated Edison Co. of New York, Inc. v. FERC*, 347 F.3d 964, 972 (D.C. Cir. 2003).

FERC reasonably decided to investigate and remedy allegations of tariff violations in seller-specific proceedings under § 309, rather than in a PNW-focused market-wide § 206 proceeding. Proceedings to investigate alleged tariff violations raise legal and factual questions different from proceedings concerning just-and-reasonable rates. The latter turn on market-wide conditions and remedies; the former focus on specific seller conduct. Because those inquiries involve different issues and evidence, implicate different parties, and impose different obligations on their participants, FERC reasonably concluded that separate proceedings would be more efficient because each would be tailored to the specific problems being addressed.

Thus, as in *Mobil Oil*, FERC "could compile" and analyze "relevant data more effectively in a separate proceeding." 498 U.S. at 230; *see also Sunray*, 391 U.S. at 49-50. By launching separate show-cause proceedings contemporaneously with its decision not to initiate a § 206 hearing for PNW transactions,

"the Commission itself has taken steps to alleviate" the related problem. *See id.* at 50. Accordingly, in ordering FERC on remand to examine allegations of tariff violations, the Ninth Circuit impermissibly interfered with FERC's ability to structure its own dockets.

III. THE DECISION BELOW IMPERMISSIBLY EXPANDS REFUND LIABILITY UNDER § 206 BEYOND THE SCOPE OF THE COMPLAINT AND CONFLICTS WITH THE D.C. CIRCUIT'S APPROACH

The Ninth Circuit erred in reversing FERC's conclusion that CDWR's transactions are outside the scope of Puget's complaint. That holding rejected FERC's contextual reading of Puget's complaint – a reading that Puget shared. The decision below conflicts with numerous D.C. Circuit precedents that defer to administrative agencies' construction of the pleadings before them, and undermines the well-established rule against retroactive ratemaking.

A. The Ninth Circuit's Approach To Interpreting Administrative Complaints Conflicts With D.C. Circuit Cases And Is Insufficiently Deferential To The Agency

1. The D.C. Circuit's standard for interpreting administrative complaints requires agencies and reviewing courts to examine an administrative complaint in its entire context. In *Burlington Northern Railroad Co. v. ICC*, 985 F.2d 589 (D.C. Cir. 1993), for example, a dispute arose over whether several complaints concerning rates for interstate rail shipments of grains were limited to grains destined for export. "[T]he complaint[s] did not clearly state whether only export traffic was being challenged." *Id.* at 594. Nevertheless, the shippers' legal theory

depended on that limiting condition. *See id.* The Interstate Commerce Commission ("ICC") therefore limited the complaints' scope to grains shipped for export as consistent with the "key element of the complainants' theory." *Id.* The D.C. Circuit upheld the ICC's interpretation of the complaints, concluding that "the shippers' [legal] analysis . . . matched the finding that they challenged only rates on export grain." *Id.* at 595.

Similarly, in *American Federation of Government Employees v. FLRA*, 796 F.2d 530 (D.C. Cir. 1986) ("*AFGE*"), the D.C. Circuit affirmed the Federal Labor Relations Authority's ("FLRA") narrowing construction of a complaint because "[t]he entire thrust of the unfair labor practice complaint" was "directed to" one legal theory and not another. *Id.* at 533. Although finding that the complainant's "broad construction of the complaint" to include another legal theory "may be colorable," the court deferred to the FLRA's narrower construction. *Id.* (complaint "precisely track[ed] the [FLRA's] standard" for one legal theory but not the other).

Those decisions establish that reviewing courts should defer to agency constructions of an administrative complaint based on the "key element[s]," *Burlington Northern*, 985 F.2d at 594, or the "entire thrust," *AFGE*, 796 F.2d at 533, of the complaint's theory of relief. The D.C. Circuit consistently defers to agencies' constructions of parties' pleadings, particularly when the pleading falls in an area in which "the Commission has greater technical expertise . . . than does the [c]ourt." *Amerada Hess Pipeline Corp. v. FERC*, 117 F.3d 596, 604 (D.C. Cir. 1997); *see Burlington Northern*, 985 F.2d at 595; *AFGE*, 796 F.2d at 533; *see also City of San Antonio v. CAB*, 374 F.2d

326, 329 n.5 (D.C. Cir. 1967) (noting that "'subordinate questions of procedure'" including "'the scope of the inquiry'" initiated by a complaint generally are "'left to the [agency's] own devising'") (quoting *FCC v. Pottsville Broad. Co.*, 309 U.S. 134, 138 (1940)).

2. By contrast, the Ninth Circuit below declined to read Puget's complaint in its proper context, as FERC did. Instead, the court focused on two sentences of the complaint, divorced from the legal theory motivating the complainant. *See* Pet. App. 31a-32a.

The Puget complaint focused on electricity purchases for PNW consumers. *See supra* pp. 5-6. Puget feared being whipsawed by the seasonal difference in retail energy demand between California and the PNW if FERC ordered price caps in California but not the PNW. As Puget's complaint explained, "absent equivalent price caps" in both regional markets, "wholesale purchasers such as [Puget] in the Pacific Northwest" would face "uncapped prices when they need power (e.g., to meet winter demand) and yet [be] hobble[d] [in] their ability to offset the costs of such purchases with uncapped prices when they have surplus power . . . for sale to California." C.A. J.E.R. 11-12 (emphasis omitted). Puget therefore requested a price cap on sales "into" the PNW equivalent to any cap the Commission might impose on California markets. *Id.* at 13.

Accordingly, FERC reasonably determined that the complaint was limited to transactions "serving load" – retail consumer demand – "in the Pacific Northwest." Pet. App. 452a. FERC adopted the ALJ's finding that CDWR's transactions were not encompassed within Puget's complaint because CDWR "is not . . . a Pacific Northwest load server." *Id.* at

432a n.43. FERC's conclusion is consistent with a straightforward reading of the "entire thrust" of Puget's complaint. *AFGE*, 796 F.2d at 533.

Instead of deferring to FERC's contextual reading of the complaint, the Ninth Circuit focused solely on two sentences from the complaint that: (a) stated that Puget sought a price cap at which sellers "'may sell capacity or energy into the Pacific Northwest's wholesale power markets'"; and (b) specified that Puget "'seeks an order that prospectively caps the prices for wholesale sales of energy or capacity into the Pacific Northwest.'" Pet. App. 31a (quoting C.A. J.E.R. 4). Based on those sentences, the court concluded that "Puget's complaint provides no indication of an intent to *exclude* refunds for energy purchased in the Pacific Northwest spot market *for consumption outside the geographical area*." *Id.* (emphases added).

The complaint, however, was far from silent on those issues. *See supra* p. 5. Puget feared having to pay uncapped prices in the winter as a net importer of energy *to serve its retail customers in the PNW*, but being unable to charge equivalent prices for its summer exports of energy to serve Californians. *See* C.A. J.E.R. 11-13. The phrase "into the Pacific Northwest" therefore clearly referenced energy sales for use in the PNW.[8]

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[8] The Ninth Circuit's other two rationales are unpersuasive. First, the court reasoned that "FERC's interpretation of Puget's complaint is also inconsistent with its prior interpretation of the complaint filed by SDG&E in the California proceeding." Pet. App. 32a. But the different aims, geographical regions, and market contexts of the two complaints accounted for FERC's differing treatments. *See* Powerex Corp. *et al.* C.A. Reh'g Pet. 15-17 (Dec. 17, 2007).

Second, the court claimed that, in *PUC*, it had upheld FERC's decision "to exclude [CDWR's] transactions from the California

The Ninth Circuit's failure to defer to FERC's contextual reading of the complaint creates a circuit conflict this Court should resolve.

B. The Ninth Circuit's Legal Standard Undercuts Long-standing Principles Of Administrative Law

The Ninth Circuit's legal standard fails to give proper deference to agency decisionmaking in areas where the agency's expertise and discretion are paramount, and undercuts the long-standing rule against retroactive ratemaking.

1. The Ninth Circuit's standard compromises the filed-rate doctrine and its implementation in § 206. *See Concord*, 955 F.2d at 71-72. That long-standing principle of rate regulation "forbids a regulated entity to charge rates for its services other than those properly filed with the appropriate federal regulatory authority." *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 (1981); *see* 16 U.S.C. § 824d(c). The filed-rate doctrine's closely related "corollary" "prohibit[s] the regulatory agency from altering a rate retroactively." *Concord*, 955 F.2d at 71; *see Arkansas Louisiana Gas*, 453 U.S. at 578. "The duty to file rates with the Commission, and the obligation to charge only those rates, have always been considered essential to preventing price discrimination[,] . . . stabilizing rates[,] . . . [and] render[ing] rates definite and certain." *Maislin Indus., U.S., Inc. v. Primary Steel, Inc.*, 497 U.S. 116, 126 (1990) (internal quotations and citations omitted). *See also Electrical Dist. No. 1 v. FERC*, 774 F.2d 490, 493 (D.C. Cir. 1985)

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proceeding based in substantial part on the existence of this proceeding involving the Pacific Northwest." Pet. App. 32a-33a. That consideration, however, is irrelevant to Puget's intent regarding its complaint and finds no support in *PUC*.

(Scalia, J.) ("[p]roviding . . . necessary predictability" in rates "is the whole purpose of the well established 'filed rate' doctrine").

Section 206 authorizes FERC to grant refunds of rates subject to constraints consistent with the filed-rate doctrine's purposes. A complaint seeking refunds must first "state the change or changes" sought by the complainant. 16 U.S.C. § 824e(a). If FERC holds a hearing on the complaint, it must "specify the issues to be adjudicated." *Id.* If, after hearing, FERC finds the complained-of rate to be unjust or unreasonable, it may order refunds only for a period after the "refund effective date." *Id.* § 824e(b). Together, these provisions ensure that, "once a complaint is filed, sellers are on notice that their sales may be subject to refund." *PUC*, 462 F.3d at 1063.

This notice is critical to the statutory structure. It allows FERC to grant refunds without interfering with the certainty and predictability of rates. Indeed, the filed-rate doctrine "does not extend to cases in which buyers are on adequate notice that resolution of [a complaint] may cause a later adjustment to the rate being collected at the time of service." *Northwest Pipeline Corp. v. FERC*, 61 F.3d 1479, 1490-91 (10th Cir. 1995) (internal quotations omitted). Such notice enables parties to know that refunds are possible *when they enter into the transaction*. *See Louisiana Pub. Serv. Comm'n v. FERC*, 482 F.3d 510, 520 (D.C. Cir. 2007). FERC must read the complaint in light of its entire context, therefore, to judge accurately whether market participants received notice that "a rate is tentative and may be later adjusted with retroactive effect." *Consolidated Edison*, 347 F.3d at 969.

2. This case presents a particularly egregious example of the problem. Puget filed its complaint in October 2000. *See* Pet. App. 10a-11a. CDWR did not begin purchasing energy for California consumption until January 2001. *See PUC*, 462 F.3d at 1042. The California parties did not claim that the PNW proceeding encompassed CDWR's transactions until August 2001 – *after* FERC had ruled that those transactions were outside the complaint that initiated the California refund proceeding. *See* C.A. J.E.R. 170-75; Pet. App. 85a-86a. Importantly, Puget – the complainant – *agreed* with FERC's interpretation that CDWR's transactions were outside the scope of Puget's complaint. Puget received *all* of the relief its complaint sought when FERC ordered region-wide rate caps in June 2001.

The Ninth Circuit's erroneous approach to administrative complaint interpretation takes a fully satisfied complaint seeking price caps for PNW electricity transactions and transforms it into a multi-billion dollar proceeding focused on California transactions for which CDWR declined to file its own timely complaint for refunds. Sellers had no notice when Puget filed its PNW-focused complaint that transactions they made months later to a public entity in California might be subject to refunds. The Ninth Circuit's dramatic expansion of the refund proceedings, therefore, significantly prejudices those sellers. They face enormous legal uncertainty over voluminous transactions completed nearly a decade ago.

IV. THIS CASE PRESENTS QUESTIONS OF NATIONAL IMPORTANCE

The California energy crisis occurred almost a decade ago, yet the participants in that crisis – buyers, sellers, public utilities, marketers, government bodies, and foreign entities – remain mired in litigation. The Ninth Circuit's approach to managing these cases has stymied FERC's ability to comply with Congress's directive "to conclude its investigation" into the California energy crisis "as soon as possible," Energy Policy Act of 2005, Pub. L. No. 109-58, § 1824(1), 119 Stat. 594, 1134, and denied procedural fairness to companies that in any other circumstance or circuit would have prevailed under long-standing principles.

The Ninth Circuit's decision here reopens a closed administrative proceeding and restarts litigation over stale events. By achieving that result through novel departures from bedrock administrative law principles, the Ninth Circuit's approach either augurs ill for defendants in future administrative complaint proceedings or, if the decision below is confined, portends "California-energy-crisis-only" administrative principles that tip the scales against non-California entities caught up in that litigation. Neither result should be tolerated by this Court.

CONCLUSION

The petition for a writ of certiorari should be granted.

Respectfully submitted,

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September 4, 2009

Supreme Court, U.S.
FILED

No. 09-288 SEP 4 - 2009

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IN THE
Supreme Court of the United States

PUGET SOUND ENERGY, INC., AVISTA CORPORATION, AVISTA ENERGY, INC., CONSTELLATION ENERGY COMMODITIES GROUP, INC., IDACORP ENERGY L.P., MORGAN STANLEY CAPITAL GROUP INC., PORTLAND GENERAL ELECTRIC COMPANY, POWEREX CORP., SEMPRA ENERGY TRADING LLC, SHELL ENERGY NORTH AMERICA (US), L.P., AND TRANSCANADA ENERGY LTD.,
Petitioners,

v.

PEOPLE OF THE STATE OF CALIFORNIA, ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Ninth Circuit

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

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UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

No. 03-74139

PORT OF SEATTLE, WASHINGTON,
Petitioner,

IDACORP ENERGY; WILLIAMS POWER COMPANY INC.; CITY OF TACOMA, WASHINGTON; SOUTHERN CALIFORNIA EDISON COMPANY; CONSTELLATION POWER SOURCE INC.; EL PASO MERCHANT ENERGY L.P.; MORGAN STANLEY CAPITAL GROUP, INC.; TRACTEBEL ENERGY MARKETING INC.; BP ENERGY CO.,
Intervenors,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent,

M-S-R PUBLIC POWER AGENCY; DUKE ENERGY TRADING AND MARKETING, LLC; PUGET SOUND ENERGY; CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER; SEMPRA ENERGY TRADING CORP.; ENERGY PLUS LLC; NORTHERN CALIFORNIA POWER AGENCY,
Intervenors,

PORT OF SEATTLE,
Applicant-Intervenor.

No. 03-74472

CITY OF SEATTLE,
Petitioner,

IDACORP ENERGY L.P.; PEOPLE OF THE STATE OF CALIFORNIA; PORT OF SEATTLE; DUKE ENERGY NORTH AMERICA, LLC, DUKE ENERGY TRADING AND MARKETING, LLC (COLLECTIVELY, "DUKE ENERGY"); CITY OF TACOMA,
Intervenors,

BENTON COUNTY, FRANKLIN COUNTY, GRANT COUNTY; TRANSCANADA ENERGY; PUBLIC SERVICE COMPANY OF COLORADO; POWEREX CORP.; CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION; ALCOA INC.; COLUMBIA FALLS ALUMINUM COMPANY, LLC; WILLIAMS POWER COMPANY INC.; CALIFORNIA ELECTRICITY OVERSIGHT BOARD; PORTLAND GENERAL ELECTRIC COMPANY; NORTHERN CALIFORNIA POWER AGENCY; EL PASO MERCHANT ENERGY L.P.,
Intervenors,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent,

AVISTA CORPORATION; AVISTA ENERGY; THE CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER; SEMPRA ENERGY; PUGET SOUND ENERGY; PINNACLE WEST COS.; CONSTELLATION ENERGY COMMODITIES GROUP, INC.; BP ENERGY CO.; TRACTEBEL ENERGY MARKETING INC.; M-S-R PUBLIC POWER AGENCY; MODESTO IRRIGATION DISTRICT (MID); THE CITY OF SANTA CLARA; CITY OF REDDING; CORAL POWER; PPL ENERGYPLUS, LLC; PPL MONTANA,
Intervenors.

No. 03-74769

CITY OF TACOMA, WASHINGTON,
Petitioner,

DUKE ENERGY NORTH AMERICA, LLC, DUKE ENERGY TRADING AND MARKETING, LLC (COLLECTIVELY, "DUKE ENERGY"); CALIFORNIA ATTORNEY GENERAL; PORT OF SEATTLE,
Intervenors,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent,

IDACORP ENERGY L.P.; PINNACLE WEST CAPITAL CORPORATION; NORTHERN CALIFORNIA POWER AGENCY; AVISTA ENERGY INC.; AVISTA CORPORATION; M-S-R PUBLIC POWER AGENCY; PUBLIC SERVICE COMPANY OF COLORADO; CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER; SEMPRA ENERGY TRADING CORP.; PUBLIC SERVICE COMPANY OF NEW MEXICO; PPL ENERGYPLUS; PPL MONTANA; CORAL POWER, LLC,
Intervenors.

No. 04-70110

PUGET SOUND ENERGY,
Petitioner,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent,

DUKE ENERGY NORTH AMERICA, LLC, DUKE ENERGY TRADING AND MARKETING, LLC (COLLECTIVELY, "DUKE ENERGY"); CITY OF TACOMA, WASHINGTON; CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION; PUBLIC SERVICE COMPANY OF COLORADO; SEMPRA ENERGY TRADING CORP.; CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER; PINNACLE WEST CAPITAL CORPORATION, (PNW); CORAL POWER, LLC; TRANSCANADA ENERGY LTD.; WILLIAMS POWER COMPANY INC.; NORTHERN CALIFORNIA POWER AGENCY (NCPA); PORT OF SEATTLE WASHINGTON; M-S-R PUBLIC POWER AGENCY; THE MODESTO IRRIGATION DISTRICT ("MID"), THE CITY OF SANTA CLARA, CALIFORNIA ("SANTA CLARA") AND THE CITY OF REDDING, CALIFORNIA ("REDDING"); CALIFORNIA ELECTRICITY OVERSIGHT BOARD; ALCOA INC.; COLUMBIA FALLS ALUMINUM COMPANY, LLC ("CFAC"); MORGAN STANLEY CAPITAL GROUP, INC.; PACIFICORP; PEOPLE OF THE STATE OF CALIFORNIA, EX REL. BILL LOCKYER, ATTORNEY GENERAL,
Applicants-Intervenors.

No. 04-70185

PEOPLE OF THE STATE OF CALIFORNIA;
BILL LOCKYER, ATTORNEY GENERAL,
Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent,

MORGAN STANLEY CAPITAL GROUP, INC.,
Applicant-Intervenor.

No. 04-70703

PEOPLE OF THE STATE OF CALIFORNIA,
Petitioner,

CITY OF TACOMA, WASHINGTON;
PORT OF SEATTLE, WASHINGTON,
Intervenors,

IDACORP ENERGY L.P.; CALIFORNIA ELECTRICITY OVERSIGHT BOARD; TRANSCANADA ENERGY LTD.; BENTON, FRANKLIN AND GRANT COUNTY, WASHINGTON PUBLIC UTILITY DISTRICTS; THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION; COLUMBIA FALLS ALUMINUM COMPANY, LLC; ALCOA, INC.; PORTLAND GENERAL ELECTRIC COMPANY; BONNEVILLE POWER ADMINISTRATION; POWEREX CORP.; BENTON COUNTY; FRANKLIN COUNTY; GRANT COUNTY, WASHINGTON,
Intervenors,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent,

BP ENERGY COMPANY; CONSTELLATION ENERGY COMMODITIES GROUP, INC.; CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER; SEMPRA ENERGY TRADING CORP.; PUGET SOUND ENERGY, INC.; AVISTA ENERGY, INC.; CORAL POWER, L.L.C.; NORTHERN CALIFORNIA POWER AGENCY; THE M-S-R PUBLIC POWER AGENCY; MODESTO IRRIGATION DISTRICT (MID); CITY OF SANTA CLARA, CALIFORNIA; CITY OF REDDING, CALIFORNIA; PINNACLE WEST COMPANIES; PUBLIC SERVICE COMPANY OF COLORADO; PPL ENERGYPLUS, LLC; PPL MONTANA, LLC; AVISTA CORPORATION,
Intervenors.

No. 04-71189

CALIFORNIA PUBLIC UTILITIES COMMISSION,
Petitioner,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

Argued and Submitted Jan. 8, 2007
Filed Aug. 24, 2007

On Petition for Review of an Order of the Federal Energy Regulatory Commission.
FERC No. Federal Power Act, FERC No. EL-01-10.

Before: SIDNEY R. THOMAS, M. MARGARET McKEOWN, and RICHARD R. CLIFTON, Circuit Judges.

Opinion by Judge THOMAS; Concurrence by Judge McKEOWN.

THOMAS, Circuit Judge:

This is another in a series of cases arising out of the energy crisis that occurred in California and other western states in 2000 and 2001. We are asked to review the decision by the Federal Energy Regulatory Commission ("FERC" or "Commission") to deny refunds to wholesale buyers of electricity that purchased energy in the short-term supply market at unusually high prices in the Pacific Northwest. We are also asked to review FERC's decision to exclude from any potential refund those transactions involving energy purchased in the Pacific Northwest for

consumption in California. We conclude that we have jurisdiction over FERC's decision to deny refunds, and that FERC abused its discretion in denying potential relief for transactions involving energy that was ultimately consumed in California. We also conclude that in determining whether refunds were warranted, FERC should have considered new evidence of intentional market manipulation submitted by the parties with FERC's approval. At this time, we decline to reach all other issues raised by the parties. We grant the petitions for review in part and remand this case to FERC to address the market manipulation evidence, to include the California-consumed energy in its analysis, and to further consider its refund decision in light of related, intervening opinions of this court.

I

The California energy crisis serves as the backdrop of this litigation. That crisis has been well-documented, *see, e.g.*, *Pub. Utils. Comm'n of State of Cal. v. FERC*, 462 F.3d 1027, 1036-44 (9th Cir.2006) ("*Pub. Utils. Comm'n*"); *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 910-14 (9th Cir.2005) ("*BPA*"); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1008-11 (9th Cir.2004) ("*Lockyer*"), and a full recitation of its history is unnecessary here.

In the mid-1990's, the California legislature deregulated the electricity market, ostensibly to reduce energy prices for consumers. Act of September 23, 1996, 1996 Cal. Legis. Serv. 854 (codified at Cal. Pub. Util.Code §§ 330-398.5). Shortly thereafter, for a variety of reasons related to the deregulation and other market factors, wholesale electricity prices skyrocketed. In May 2000, for instance, average prices in the California short-term supply market, also known as the "spot market," were twice as high

as average prices in May 1999. *Pub. Utils. Comm'n*, 462 F.3d at 1040. In June 2000, the first in a series of power blackouts occurred in Northern California, potentially as the result of market manipulation. *Id.*

The effects of this crisis were felt in other areas of the western energy market as well, as "dysfunctions in the spot markets operated by the [California Independent System Operator] and California Power Exchange (PX) affected the prices in the Pacific Northwest," due to the "integrated nature of the Western markets." *Puget Sound Energy, Inc., et al.*, 103 FERC ¶ 61,348 at 62,366-67 (2003) ("June 25, 2003 Order"). The Pacific Northwest is defined as Idaho, Oregon, and Washington, as well as parts of Montana, Nevada, Utah, and Wyoming. 16 U.S.C. § 839a(14).

Prices in the Pacific Northwest spot market skyrocketed during the energy crisis. Other factors, such as an extreme reduction in energy supply due to drought, also contributed to the crisis in the Pacific Northwest, a region that relies heavily on water flow through hydroelectric dams to generate electricity. *Puget Sound Energy, Inc., et al.*, 96 FERC ¶ 63,044 at 65,385 (2001) ("September 24, 2001 ALJ Report"). Unlike the California spot market, which operated through a centralized power exchange using a central clearing price, the Pacific Northwest spot market operated through bilateral contracts negotiated independently between buyers and sellers, without a central clearing price. June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,367. Most of these contracts were entered into under the terms of the Western Systems Power Pool ("WSPP") Agreement, a standard form contract for electricity sales. September 24, 2001 ALJ Report, 96 FERC ¶ 63,044 at 65,386.

Under the Federal Power Act ("FPA"), all rates charged by a public utility – defined, confusingly, as a nongovernmental entity, *BPA*, 422 F.3d at 917 – must be "just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful," 16 U.S.C. § 824d(a). Under § 206 of the FPA, FERC has the authority to investigate, on its own initiative or at the request of a complaining party, whether a particular rate is "just and reasonable." *Pub. Utils. Comm'n*, 462 F.3d at 1045. If FERC finds a rate "unjust, unreasonable, unduly discriminatory or preferential," it must determine a just and reasonable rate and order that rate to be "observed and in force." 16 U.S.C. § 824e(a) (2004); *Pub. Utils. Comm'n*, 462 F.3d at 1045. FERC may also order sellers to pay refunds to those who bought energy at the unjust or unreasonable rate. 16 U.S.C. § 824e(b) (2004); *Pub. Utils. Comm'n*, 462 F.3d at 1045. Such refunds are limited to a fifteen-month period following the "refund effective date," which is a date FERC establishes that may be no earlier than sixty days after the filing of the complaint or, in the case of a § 206 proceeding instituted by FERC of its own accord, sixty days after FERC publishes notice of its intention to initiate the proceeding. 16 U.S.C. § 824e(b) (2004). FERC may not order any refunds for the period before the filing of the complaint or the sixty-day period immediately following that filing. *Id.*; *Pub. Utils. Comm'n*, 462 F.3d at 1045.

Pursuant to the FPA, San Diego Gas & Electric ("SDG & E") filed a complaint with FERC regarding the skyrocketing energy prices in California. *See BPA*, 422 F.3d at 912-13. Shortly thereafter, on October 26, 2000, Puget Sound Energy ("Puget") – one of the parties now supporting FERC's decision – filed a complaint with FERC requesting price caps

for sales of capacity or energy into Pacific Northwest wholesale power markets. Puget requested a prospective price cap equal to the lowest cap established by FERC in the California markets. Puget's complaint alleged that the California and Pacific Northwest markets were part of the same integrated market of the Western Interconnection, and that market conditions in California influenced market conditions in the Pacific Northwest. The complaint also requested that FERC set a refund effective date, to the extent refunds were necessary, sixty days after the filing of the complaint, or December 25, 2000, the earliest possible refund effective date pursuant to 16 U.S.C. § 824e(b). FERC's notice of the Puget complaint was published in the Federal Register on November 8, 2000, stating that "[t]he Complaint seeks a refund effective date, to the extent any refund is called for, of sixty days after the filing of the Complaint." Puget Sound Energy, Inc., et al.; Electric Rate and Corporate Regulation Filings, 65 Fed.Reg. 66,986 (Nov. 8, 2000).

On December 15, 2000, shortly after finding that prices in the California spot markets were unjust and unreasonable, *Pub. Utils. Comm'n*, 462 F.3d at 1041; *San Diego Gas & Elec. Co., et al.*, 93 FERC ¶ 61,121 at 61,349 (2000), FERC dismissed Puget's complaint, *San Diego Gas & Elec. Co., et al.*, 93 FERC ¶ 61,294 at 62,019 (2000) ("December 15, 2000 Order"). Puget filed a timely request for rehearing on January 12, 2001. On April 26, 2001, in response to the SDG & E complaint, FERC imposed price caps on sales in the California spot markets and instituted a "West-Wide 206 Investigation" into rates in spot markets outside of California, believing that such rates might be unjust and unreasonable. *San Diego Gas & Elec. Co., et al.*, 95 FERC ¶ 61,115 at 61,365 (2001) ("April 26,

2001 Order"). Then, on June 19, 2001, acknowledging that "the California market is integrated with those of other states in the [West]," FERC adopted "a market monitoring and mitigation plan for the [western] spot markets." *San Diego Gas & Elec. Co., et al.*, 95 FERC ¶ 61,418 at 62,567-68 (2001) ("June 19, 2001 Order"). The "need for uniform pricing throughout the Western region" made this plan necessary. *Id.* at 62,568. FERC also ordered market participants to engage in settlement discussions, with the goal of settling past accounts. *Id.* at 62,570. Three days later, FERC clarified that the settlement proceeding was not limited to "California-related matters" but could also focus on "settling past accounts related to sales in the Pacific Northwest." *San Diego Gas & Elec. Co., et al.*, 95 FERC ¶ 61,425 at 62,583 (2001) ("June 22, 2001 Order").

Also on June 22, 2001, Puget filed a motion to dismiss and a notice that it was withdrawing its complaint, explaining that the June 19, 2001 Order instituting price mitigation in the Pacific Northwest satisfied its complaint. On July 9, 2001, the Port of Seattle and the City of Tacoma filed an answer opposing Puget's motion, explaining that a dismissal would prejudice other entities in the Pacific Northwest that relied on Puget's complaint. On the same day, the City of Seattle and the Attorney General of Washington filed late motions to intervene as well as answers in opposition to Puget's notice of withdrawal. Although it does not normally grant late interventions, FERC granted the late motions to intervene filed by the City of Seattle and the Attorney General of Washington because "over the course of the SDG & E proceeding, [FERC] has expanded the scope of its focus from just California to include the entire Western interconnect and also to implicate

wholesale spot market transactions of non-public utilities." *San Diego Gas & Elec. Co., et al.*, 96 FERC ¶ 61,120 at 61,504 (2001) ("July 25, 2001 Order"). The next day, July 26, 2001, the Port of Seattle and the City of Tacoma also filed late motions to intervene in the Puget proceeding. FERC granted those motions as well.

In its July 25, 2001 Order, FERC noted that there had been little time during the California settlement discussions to address issues raised by the Pacific Northwest parties. *Id.* at 61,520. As a result, FERC directed "all parties to the Puget Sound complaint proceeding to participate in [a separate preliminary evidentiary proceeding] and to focus on settling past accounts related to spot market sales in the Pacific Northwest. Interested parties to the SDG & E proceeding may participate at their discretion." *Id.* at 61,520-21. The purpose of the "separate preliminary evidentiary proceeding," FERC explained, would be to "facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001." *Id.* at 61,520.

The preliminary evidentiary proceeding took place from August 1, 2001, to September 17, 2001. The administrative law judge ("ALJ") expedited the proceeding by limiting discovery responses to four business days, prohibiting depositions, and conducting a three-day hearing in which cross-examination was frequently waived. September 24, 2001 ALJ Report, 96 FERC ¶ 63,044 at 65,300. The ALJ found that although prices in the California energy markets affected prices in the Pacific Northwest, "this was not the only thing driving up the prices" there. *Id.* at 65,370. The ALJ also found no evidence of the

exercise of market power in the Pacific Northwest, *id.* at 65,369, and found that the Pacific Northwest spot market "performed as a competitive market" during the relevant period, *id.* at 65,386. As a result, the ALJ determined that prices were not unjust or unreasonable and that refunds were unwarranted. *Id.* at 65,385. The ALJ also determined that transactions in the Pacific Northwest spot market involving energy that was consumed in California could not be refunded in the Pacific Northwest proceeding because such transactions were beyond the scope of the Puget complaint. *Id.* at 65,331.

On May 6, 2002, FERC released on its website documents relating to Enron's manipulation of the California energy markets. According to the parties seeking refunds, this new evidence also reflected on market manipulation in the Pacific Northwest because some of Enron's tactics relied on the import and export of electricity to and from California and the Pacific Northwest. The parties seeking refunds also allege that Enron relied on counterpart energy sellers in the Pacific Northwest to carry out its manipulative strategies.

In response to this newly-released evidence of Enron's intentional market manipulation, some of the parties filed motions to reopen the evidentiary record in the Puget complaint. On December 19, 2002, FERC agreed to reopen the evidentiary record, giving the parties until February 28, 2003, to submit "additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001 and proposed new and/or modified findings of fact." *Puget Sound Energy, Inc., et al.*, 101 FERC ¶ 61,304 at 62,221 (2002) ("December 19, 2002 Order"). FERC later extended the deadline for

submitting additional evidence to March 17, 2003. *Puget Sound Energy, Inc., et al.*, 102 FERC ¶ 61,163 at 61,444 (2002).

After receiving the new evidence and holding oral argument, FERC ruled on the ALJ's findings. A divided three-commissioner panel agreed with the ALJ, denying the request for refunds for energy purchases in the Pacific Northwest spot market. June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,367; *Puget Sound Energy, Inc., et al.*, 105 FERC ¶ 61,183 (2003) ("November 10, 2003 Order"). FERC did not, however, respond to or take into account the new evidence of Enron's market manipulation submitted with FERC's approval. FERC also declined to make an explicit finding as to whether spot market prices in the Pacific Northwest were unjust or unreasonable, instead concluding that even if prices were unreasonable, the balance of factors tipped against ordering refunds. June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,367. These equitable factors included, *inter alia*, (1) the presence in the Pacific Northwest market of governmental entities not subject to FERC's jurisdiction and thus not liable for refunds, (2) the unfairness of awarding refunds to parties that imprudently relied on the spot market for their energy needs, (3) the adverse consequences refunds might have on the market, and (4) the time and effort required to calculate refunds in the Pacific Northwest bilateral spot market. *Id.* at 62,367-69. FERC also affirmed the recommendation of the ALJ to exclude from the refund proceeding transactions involving energy that was ultimately consumed in California. November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,964 n. 43; *Puget Sound Energy, Inc., et al.*, 106 FERC ¶ 61,109 at 61,368 (2004) ("February 9, 2004 Order"). Commissioner Massey dissented

stating that he would order refunds from the refund effective date, December 25, 2000, through June 20, 2001. June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,370.

In this appeal, governmental entities from the Pacific Northwest – the City of Seattle, the Port of Seattle, and the City of Tacoma, all of which purchased, on the whole, more electricity during the energy crisis than they sold – petition for review of FERC's decision to deny refunds. The State of California, the Public Utilities Commission of California, and the California Electricity Oversight Board ("the California Parties"), petition for review of FERC's decision to exclude from the refund proceeding transactions involving energy that was ultimately consumed in California, as well as FERC's decision to deny refunds. These parties will be referred to, collectively, as the "Refund Proponents." Supporting FERC's decision to deny refunds are the Bonneville Power Administration, Puget – the public utility that filed the initial complaint in this proceeding but which now opposes refunds – and many other public utility intervenors. These parties will be referred to, collectively, as the "Refund Opponents."

II

We review FERC orders to determine whether they are "arbitrary, capricious, an abuse of discretion, unsupported by substantial evidence, or not in accordance with law." *Cal. Dep't of Water Res. v. FERC*, 341 F.3d 906, 910 (9th Cir.2003). We defer to FERC's factual findings if those findings are supported by substantial evidence. 16 U.S.C. § 825*l*(b); *Bear Lake Watch, Inc. v. FERC*, 324 F.3d 1071, 1076 (9th Cir.2003). Substantial evidence "'means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.'" *Bear Lake*

Watch, 324 F.3d at 1076 (quoting *Eichler v. SEC*, 757 F.2d 1066, 1069 (9th Cir.1985)). "'If the evidence is susceptible of more than one rational interpretation, we must uphold [FERC's] findings.'" *Id.* (quoting *Eichler*, 757 F.2d at 1069) (alteration in original). We review questions of law de novo. *Am. Rivers v. FERC*, 201 F.3d 1186, 1194 (9th Cir.1999). FERC's interpretation of the FPA is reviewed under the analysis established in *Chevron U.S.A. Inc. v. Natural Res. Def. Council*, 467 U.S. 837, 842, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984), and its progeny, *BPA*, 422 F.3d at 914.

As a threshold matter, we must determine whether we have jurisdiction to review FERC's decision to deny refunds for energy transactions in the Pacific Northwest. FERC contends that we lack jurisdiction to review its denial of refunds because this decision is committed to agency discretion by law.

We lack jurisdiction to review "an agency's decision not to prosecute or enforce, whether through civil or criminal process." *Heckler v. Chaney*, 470 U.S. 821, 831, 105 S.Ct. 1649, 84 L.Ed.2d 714 (1985); 5 U.S.C. § 701(a)(2). This is because "an agency decision not to enforce often involves a complicated balancing of a number of factors which are peculiarly within its expertise," such as questions about the best use of the agency's resources. *Heckler*, 470 U.S. at 831, 105 S.Ct. 1649. The Supreme Court has cautioned, however, that this exception to judicial review is a narrow one, *id.* at 838, 105 S.Ct. 1649; *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 410, 91 S.Ct. 814, 28 L.Ed.2d 136 (1971), *overruled on other grounds by Califano v. Sanders*, 430 U.S. 99, 97 S.Ct. 980, 51 L.Ed.2d 192 (1977), limited to those situations in which there is no meaningful standard against which to judge an agency's decision not to

act, *Heckler*, 470 U.S. at 830, 105 S.Ct. 1649. In those situations, the concern is that courts should not intrude upon an agency's prerogative to pick and choose its priorities, and allocate its resources accordingly, by demanding that an agency prosecute or enforce. Thus, *Heckler* limited the presumption of unreview ability to "agency *refusals to institute* investigative or enforcement proceedings." *Id.* at 838, 105 S.Ct. 1649 (emphasis added). When an agency *has instituted* proceedings, meaningful standards exist to review what the agency has done: "when an agency *does* act to enforce, that action itself provides a focus for judicial review, inasmuch as the agency must have exercised its power in some manner. The action at least can be reviewed to determine whether the agency exceeded its statutory powers." *Id.* at 832, 105 S.Ct. 1649 (emphasis in original). *See also MCI Telecomms. Corp. v. FCC*, 917 F.2d 30, 41-42 (D.C.Cir.1990) ("It is one thing for the FCC to decline to investigate a tariff in the first place; that decision is entrusted to its unreviewable discretion. It is quite another for it to note the importance of a question concerning a tariff, request and take evidence from the parties, and hold a hearing on the matter. . . ."). Accordingly, where FERC has made a determination to adjudicate a dispute or take steps towards enforcing a violation of the law, the outcome it chooses is subject to judicial review under the standards of review set forth in the Administrative Procedure Act ("APA"). 5 U.S.C. § 706; *Cal. Dep't of Water Res.*, 341 F.3d at 910.

That is the case here. FERC has already made a decision to commit resources to an examination of whether refunds are warranted for certain energy transactions in the Pacific Northwest for a period of time in 2000 and 2001. In response to the filing of a

complaint, FERC has held hearings and taken evidence to adjudicate a dispute between the parties as to whether refunds should be awarded. Although the steps FERC has taken do not require FERC to find that refunds are appropriate, FERC's decision regarding the propriety of awarding refunds is reviewable by this court. Indeed, we regularly exercise judicial review over FERC's decision to grant or deny refunds, *Pub. Utils. Comm'n*, 462 F.3d 1027 (reviewing decision to grant refunds); *Lockyer*, 383 F.3d 1006 (reviewing decision to deny refunds); *Consol. Edison Co. of N.Y., Inc. v. FERC*, 347 F.3d 964 (D.C.Cir. 2003) (reviewing decision to deny refunds), and we do so here.

III

We also must decide whether FERC erred in finding that Puget's original complaint, which launched the Pacific Northwest refund proceeding, was not withdrawn as a matter of law in July 2001. If FERC erred and the opinion was withdrawn, the entire Pacific Northwest evidentiary proceeding before the ALJ, as well as FERC's subsequent decision to deny refunds, would be procedurally barred. If, on the other hand, we determine that Puget's complaint was not withdrawn, we must decide whether the Puget complaint failed to set a refund effective date, which is a statutory requirement for seeking refunds. In other words, Puget and the Refund Opponents ask us to affirm the outcome below on procedural grounds, rather than reach the merits. This we decline to do.

A

As a threshold matter, we conclude that Puget has standing to assert this challenge, even though it was the prevailing party before the agency. The FPA limits judicial review to those parties who have been "aggrieved by an order issued by the Commission."

16 U.S.C. § 825*l*(b). In addition, "[l]ike all parties seeking access to the federal courts, [Puget is] held to the constitutional requirement of standing." *Shell Oil Co. v. FERC*, 47 F.3d 1186, 1200 (D.C.Cir.1995). The D.C. Circuit has held that both aggrievement and standing require "that petitioners establish, at a minimum, 'injury in fact' to a protected interest." *Id.* (interpreting the similar aggrievement requirement of 28 U.S.C. § 2344).

"[M]ere disagreement with an agency's rationale for a substantively favorable decision, even where such disagreement focuses on an interpretation of law to which a party objects, does not constitute the sort of injury necessary for purposes of Article III standing . . . ." *Id.* at 1202 (internal quotation marks omitted). The general rule is that a party may not appeal from a decree in its favor. *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 176, 54 S.Ct. 658, 78 L.Ed. 1182 (1934). There are, however, exceptions to the general rule, one of which we find applicable here. This is the exception for cross-appellants who "might become aggrieved upon reversal on the direct appeal." *Hilton v. Mumaw*, 522 F.2d 588, 603 (9th Cir.1975). In such a case, "the risk that [a cross-appellant] might become aggrieved upon reversal on the direct appeal is sufficient" to confer standing, even when "the final order from which the direct appeal was taken was entirely favorable to cross-appellants." *Id.*

Puget undoubtedly prevailed before the agency; indeed, it argues that FERC reached the correct result in not granting refunds. Puget has standing, however, because, while not technically bringing a cross-appeal, it essentially finds itself in the position of a cross-appellant who lost a collateral issue below but ultimately prevailed. With the Refund Propo-

nents appealing FERC's denial of refunds, FERC's collateral refusal to let Puget withdraw its complaint would expose Puget to greater refund liability should we reverse. Accordingly, under *Hilton*, the risk that Puget "might become aggrieved upon reversal" allows it to bring this appeal.

B

Although it has standing to raise them, Puget's procedural arguments are unavailing. On June 19, 2001, FERC extended price mitigation beyond California to the rest of the western states, including the Pacific Northwest. June 19, 2001 Order, 95 FERC ¶ 61,418 at 62,568. The June 19, 2001 Order also required public utility sellers and buyers to engage in settlement discussions to determine the amount of refunds owed. *Id.* at 62,570. Three days later, on June 22, 2001, FERC clarified that the settlement discussions should not be limited to California entities but "may also focus on settling past accounts related to sales in the Pacific Northwest." June 22, 2001 Order, 95 FERC ¶ 61,425 at 62,583. On the same day, Puget filed a motion to dismiss its complaint and notice of withdrawal.

Puget contends that its notice of withdrawal of the complaint upon which the Pacific Northwest refund proceeding is based became effective as a matter of law fifteen days after Puget filed the notice, nullifying the entire refund proceeding at issue in this case. Puget's argument is that although some Refund Proponents filed motions in opposition to Puget's notice, these motions in opposition could not have prevented Puget's withdrawal from going into effect because the Refund Proponents were not, at that time, parties to the proceeding. Because we must defer to FERC's interpretation of its own regulation "so long as [the interpretation] is not plainly erroneous or inconsis-

tent with the regulation," *Entergy Servs., Inc. v. FERC*, 375 F.3d 1204, 1209 (D.C.Cir.2004) (internal quotation marks omitted), we disagree.

FERC's regulations provide that a withdrawal "of any pleading is effective at the end of 15 days from the date of filing . . . if no motion in opposition to the notice of withdrawal is filed within that period and the decisional authority does not issue an order disallowing the withdrawal within that period." 18 C.F.R. § 385.216(b)(1). If, on the other hand, "a motion in opposition to a notice of withdrawal is filed within the 15 day period, the withdrawal is not effective until the decisional authority issues an order accepting the withdrawal." *Id.* § 385.216(b)(2). Puget contends that although the Refund Proponents opposed Puget's notice, this opposition was not effective because another regulation states that motions may be filed only by "a participant or a person who has filed a timely motion to intervene which has not been denied."[1] *Id.* § 385.212(a)(2). The regulations in turn define "participant" as "any party" or any employee of the Commission. *Id.* § 385.102(b). A "party" is one who has filed the complaint, is a respondent to the proceeding, or who has effectively intervened. *Id.* § 385.102(c). The process of intervening, not particularly relevant here, is laid out at 18 C.F.R. § 385.214.

FERC has interpreted 18 C.F.R. § 385.216(b)(1) as placing no limitation on who may oppose a party's notice of withdrawal. June 25, 2003 Order, 103

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[1] Although the language permitting "a person who has filed a *timely* motion to intervene which has not been denied," 18 C.F.R. § 385.212(a)(2) (emphasis added), might apply to someone not yet officially a "participant" or "party," none of the Refund Proponents would fall into this category because their motions to intervene were filed out of time.

FERC ¶ 61,348 at 62,365 n. 19. In the alternative, FERC also interpreted the regulations as permitting a non-party to oppose the withdrawal of a complaint by simultaneously filing a motion in opposition to withdrawal as well as a motion to intervene. *Id.*; November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,958-59. In that situation, according to FERC, even if FERC did not grant the motion to intervene until a later date, it could have granted the motion to intervene on the day both motions were filed, thus making the non-party an intervening party capable of filing a motion in opposition under 18 C.F.R. § 385.212(a)(2). June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,365 n. 19; November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,958-59. Accordingly, because the Attorney General of Washington and the City of Seattle filed, on July 9, 2001, simultaneous motions to intervene and motions in opposition to the withdrawal, November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,958 n. 13, FERC rejected Puget's argument that its complaint had been withdrawn as a matter of law fifteen days after Puget filed its notice of withdrawal, *id.* at 61,958-59.[2]

We see no error in FERC's interpretation of its own regulations. The regulation addressing notices of withdrawal does not explicitly state that opposition to such notices may be made only by formal parties to the proceeding. 18 C.F.R. § 385.216(b)(1). FERC did not err in treating the Attorney General of Washington and the City of Seattle as intervenors for pur-

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[2] The City of Tacoma and the Port of Seattle did not file their motions to intervene in the Pacific Northwest proceeding until July 26, 2001, nearly three weeks after filing their motions in opposition to the withdrawal. They had, however, intervened in the California refund proceeding at the time they opposed Puget's notice of withdrawal.

poses of opposing Puget's notice of withdrawal. We also find support for FERC's decision in the fact that FERC granted the City of Tacoma and the Port of Seattle party status in the California refund proceeding on July 9, 2001. *See Domtar Maine Corp. v. FERC*, 347 F.3d 304, 309 (D.C.Cir.2003) (permitting retroactive grant of intervention). Given the extremely close ties between the California proceeding and the Pacific Northwest proceeding, and FERC's frequent treatment of the two refund proceedings as one and the same, *see, e.g.*, June 22, 2001 Order, 95 FERC ¶ 61,425 at 62,583 (using the SDG & E heading and clarifying that "all parties to the SDG & E complaint proceeding . . . may also focus on settling past accounts related to sales in the Pacific Northwest"), FERC could also have accepted the opposition motions of Tacoma and the Port of Seattle as filed by parties to the proceeding. For these reasons, we hold that the withdrawal of Puget's complaint did not become effective as a matter of law, and FERC may use the complaint as a basis for awarding refunds in the Pacific Northwest.

C

The Refund Opponents supporting Puget further argue the Pacific Northwest proceeding was procedurally doomed because Puget's complaint did not request a required "refund effective date," thus stripping FERC of any authority to order refunds for electricity purchases in the Pacific Northwest. We reject this argument as well.

Congress has provided that "[w]henever [FERC] institutes a proceeding under this section, [FERC] shall establish a refund effective date." 16 U.S.C. § 824e(b) (2004). This refund effective date may not be earlier than sixty days after the filing of a complaint or the filing of a notice by FERC that it

intends to investigate rates sua sponte.[3] *Id.* The refund effective date is important because any refunds ordered by FERC are limited to the fifteen-month period following the refund effective date. *Id.* Without a refund effective date, the entire Pacific Northwest proceeding would have been moot because FERC would have been powerless to order refunds for the period sought by the Refund Proponents.

The Refund Opponents argue that Puget's complaint never requested refunds or the setting of a refund effective date. To the contrary, Puget's complaint clearly stated that "[Puget] requests that any refunds ordered by the Commission reflect the prospective nature of the relief sought. If and to the extent any refund is called for in response to [Puget's] petition, [Puget] respectfully requests that the refund effective date be set . . . sixty (60) days after the date of filing of this Complaint."

In the alternative, the Refund Opponents argue that because FERC dismissed Puget's complaint on December 15, 2000, December 15, 2000 Order, 93 FERC ¶ 61,294 at 62,019-20, FERC prevented the establishment of a refund effective date even though Puget filed a petition for rehearing on January 12, 2001. In other words, they argue that buyers and sellers in the Pacific Northwest spot market could not have been on notice that December 25, 2000, may serve as the effective date for refunds because the complaint requesting that date was dismissed prior to December 25, 2000. This argument fails for two reasons. First, market participants in the Pacific

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[3] Amendments effective August 8, 2005, removed the sixty-day waiting period, permitting the refund effective date to be set as early as the date the complaint is filed or the date the Commission files notice of its investigation. 16 U.S.C. § 824e(b) (2006).

Northwest were notified prior to FERC's dismissal of the complaint that Puget had requested a refund effective date of December 25, 2000. FERC itself created a "Notice of Complaint," which stated that Puget's complaint "seeks a refund effective date, to the extent any refund is called for, of sixty days after the filing of the Complaint." FERC's notice also explained that "[c]opies of this filing were served upon parties to the WSPP, and transmitted electronically to the WSPP for posting on its website (www.wspp.org) and for electronic distribution to all parties to the WSPP Agreement." In addition, this notice was published in the Federal Register on November 8, 2000. 65 Fed.Reg. 66,986.

Second, the FPA does not support the contention of the Refund Opponents. On the one hand, the FPA provides that if FERC does not respond to an application for rehearing within thirty days after filing, the application "*may* be deemed to have been denied." 16 U.S.C. § 825*l*(a) (emphasis added). FERC's regulations make this denial automatic, stating that "[u]nless [FERC] acts upon a request for rehearing within 30 days after the request is filed, the request is denied." 18 C.F.R. § 385.713(f). On the other hand, the statute also states that until the record is filed with the court of appeals, FERC may at any time, with reasonable notice, modify or set aside any finding or order it has made. 16 U.S.C. § 825*l*(a). Thus, even if Puget's rehearing request was denied as a matter of law thirty days after it was filed, this denial did not strip FERC of its ability to change its mind and modify its decision in the June 25, 2003 Order.

Moreover, we have already explained that petitions for rehearing keep market participants on notice that an alternative refund effective date, once rejected by

FERC, might in the future be made the refund effective date. *Pub. Utils. Comm'n*, 462 F.3d at 1047 ("Further, some of the California Parties promptly sought rehearing of FERC's initial determination of the refund effective date in its August 23, 2000 Order. In short, market participants were quickly apprised that the original refund effective date might be subject to revision."). Here, Puget filed a petition for rehearing challenging FERC's order dismissing its complaint. Thus, sellers in the Pacific Northwest – who were already on notice of Puget's complaint requesting a refund effective date – were sufficiently on notice that Puget's complaint and its attendant refund effective date were still potentially viable because Puget filed a petition for rehearing. Any reliance by sellers on the lack of a refund effective date "'prior to the issuance of a final order was at their own risk.'" *Id.* (quoting December 19, 2001 Order, 97 FERC ¶61,275 at 62,198).

Finally, the Refund Opponents argue that FERC was required to set a refund effective date, if at all, *before* instituting a § 206 refund proceeding. FERC acknowledges in its brief that "[t]he Commission never established an FPA § 206(b) refund effective date for this matter . . . ." However, the plain language of the FPA does not place any restriction on when FERC may set the refund effective date. *Hertzberg v. Dignity Partners, Inc.*, 191 F.3d 1076, 1081 (9th Cir.1999) ("Where the meaning of a statute is clear from the text, we need look no further."). Rather, the statute states that "[w]henever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date." 16 U.S.C. § 824e(b). The statute mandates the establishment of an effective date, but it does not mandate when FERC must establish it. To

the extent the word "institutes" is ambiguous, connoting both that the date shall be established at the time the proceeding begins and that the date shall be established anytime FERC is involved in such a proceeding, we owe deference to FERC's interpretation of the ambiguous language. *Chevron*, 467 U.S. at 842-43, 104 S.Ct. 2778. FERC made clear its interpretation when it announced that the statute would permit FERC to set the refund effective date at December 25, 2000. June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,366 n. 25.

FERC's interpretation, which would permit it to set the refund effective date at any time, is consistent with the overall framework of the statute, which indicates the primary concern of Congress was to afford notice to market participants of the period of time during which they may be liable for refunds. The sixty-day rule provides notice to the market that if FERC ever decides to order refunds based on a given complaint, those refunds could cover a period beginning sixty days after the filing of that complaint, and no earlier. This is a permissible construction of the statute, and is supported by our prior decision regarding the California proceeding, in which we found that the "key question is whether the SDG & E complaint afforded sufficient notice to alert market participants that sales and purchases might be subject to refund." *Pub. Utils. Comm'n*, 462 F.3d at 1046. That opinion made clear that FERC has some discretion in setting "'the earliest refund effective date allowed in order to give maximum protection to consumers,'" *id.* (quoting December 19, 2001 Order, 97 FERC ¶ 61,275 at 62,198), as long as that protection is balanced against fairness to market participants by providing them with the notice necessary to

change their practices prior to the date refunds might start to accrue.

In sum, we reject the procedural challenges raised by the Refund Opponents and hold that Puget's complaint requested a refund effective date, FERC's dismissal of Puget's complaint did not disturb FERC's ability to set the refund effective date, and FERC was not required to formally set the refund effective date prior to instituting a § 206 refund proceeding. We also hold that Puget's complaint was not withdrawn as a matter of law because the Refund Proponents timely opposed Puget's notice of withdrawal. Accordingly, FERC had the authority to order refunds for transactions in the Pacific Northwest spot market during the permissible time period, although it declined to do so on the merits.

IV

The California Parties challenge FERC's decision to exclude from the Pacific Northwest refund proceeding purchases of energy made by the California Energy Resources Scheduling ("CERS") division in the Pacific Northwest spot market. CERS, a division of the California Department of Water Resources, began purchasing wholesale power on behalf of California consumers in the California and Pacific Northwest spot markets during the energy crisis. *See Pub. Utils. Comm'n*, 462 F.3d at 1042. FERC ruled that the CERS transactions were outside the scope of the Pacific Northwest refund proceeding because the Puget complaint, on which the proceeding was based, focused on sales of energy "into" the Pacific Northwest, whereas purchases made by CERS were actually purchases "into" California, where the energy was consumed. November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,964 n. 43. In addition, FERC adopted the ALJ's finding that the CERS deliveries of energy

took place in California, not in the Pacific Northwest. *Id.* FERC reaffirmed this decision when it denied the California Parties' request for rehearing. February 9, 2004 Order, 106 FERC ¶ 61,109 at 61,368 ("Clearly, Puget's complaint focus was on transactions into the Pacific Northwest, and as the ALJ explained, the bilateral transactions involving CERS were sales into California and not into the Pacific Northwest."). The February 9, 2004 Order also claimed that the ALJ had found that a witness for CERS testified that deliveries actually occurred in California, not in the Pacific Northwest. *Id.*

We cannot accept such a constrained reading of the Puget complaint. First, FERC's factual finding that the energy purchased by CERS was delivered in California is not supported by substantial evidence. The ALJ never explicitly found that a CERS witness admitted that the energy deliveries took place in California. The section in which the ALJ discusses the CERS witness is actually a recitation of arguments made by the Refund Opponents. September 24, 2001 ALJ Report, 96 FERC ¶ 63,044 at 65,312. By contrast, the ALJ's recommendations focus solely on the scope of the Puget complaint. *Id.* at 65,331. The ALJ's proposed findings of fact state that deliveries took place in California without mentioning the CERS witness and without clarifying the basis for this proposed finding. *Id.* at 65,385-86 (Proposed Findings of Fact 2 and 28). FERC, on the other hand, cites to pages in the transcript of the ALJ evidentiary proceeding where a CERS employee confirmed that physical delivery is taken within the control area of the Los Angeles Department of Water and Power. The record shows, however, that even if physical delivery of the energy took place in California, the legal change of ownership of the energy

occurred, pursuant to the Confirmation Agreement, at interconnections located within the Pacific Northwest. There is no evidence in the record suggesting that the change of ownership occurred in California, rather than in the Pacific Northwest.

Furthermore, FERC's attempt to distinguish between the location where a change of ownership of electricity occurs and the location where that electricity physically changes hands is not supported by either the law or the governing contractual agreements between CERS and energy sellers in the Pacific Northwest.

Having established that FERC could not have found, on this record, that the CERS purchases occurred in California, we must determine whether sales to CERS were outside the scope of the Pacific Northwest refund proceeding even if the legal change of ownership occurred in the Pacific Northwest. In so doing, we are mindful that we owe deference to FERC's interpretation of the scope of Puget's complaint. *Amerada Hess Pipeline Corp. v. FERC*, 117 F.3d 596, 604 (D.C.Cir.1997); *Burlington N. R.R. Co. v. ICC*, 985 F.2d 589, 595 (D.C.Cir.1993).

We conclude that FERC's interpretation of the scope of Puget's complaint is arbitrary, capricious, and an abuse of discretion. On its face, Puget's complaint provides no indication of an intent to exclude refunds for energy purchased in the Pacific Northwest spot market for consumption outside the geographical area. The complaint petitioned FERC to cap prices at which sellers subject to FERC's jurisdiction "may sell capacity or energy into the Pacific Northwest's wholesale power markets. [Puget] seeks an order that prospectively caps the prices for wholesale sales of energy or capacity into the Pacific Northwest . . . ." This language indicates that the

complaint was concerned with (1) sellers who were (2) selling energy in the Pacific Northwest market. The complaint is silent as to any constraint on the identity of the buyers or where the energy ultimately would be consumed.

FERC's interpretation of Puget's complaint is also inconsistent with its prior interpretation of the complaint filed by SDG & E in the California proceeding. That complaint similarly petitioned FERC "for an emergency order capping . . . the prices at which sellers subject to its jurisdiction may bid energy or ancillary services *into* California's two large bulk-power markets . . . ." (Emphasis added.) In contrast to its interpretation of the Puget complaint, FERC did not interpret the California complaint as limiting refunds to entities that purchased energy for ultimate consumption in California, and in fact some parties who benefitted from refunds in the California proceeding did not consume the fruits of their purchases in California. FERC's interpretation of the California complaint is the better one, and one upon which we relied, and its conflicting interpretation of a similar complaint in a similar refund proceeding renders its subsequent interpretation unworthy of deference. *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 815-16 (D.C.Cir.1998) ("[W]here an agency treats similar situations differently without reasoned explanation, its decision will be vacated as arbitrary and capricious."). Both complaints served to notify all sellers of energy in the respective markets that they may be liable for refunds for sales of energy in those markets, regardless of where the energy would be consumed.

In addition, FERC argued in the SDG & E case that the CERS transactions were the subject of other regulatory proceedings. *Pub. Utils. Comm'n*, 462

F.3d at 1064. Other entities pointed to the Pacific Northwest proceeding to argue that the CERS transactions were outside the scope of the California proceeding. We accepted these arguments and excluded the CERS transactions from that case. *Id.* at 1063-64. It would be inconsistent with our reasoning to exclude the transactions from the California proceeding based in substantial part on the existence of this proceeding involving the Pacific Northwest market, and then to exclude the transactions from this proceeding based on the argument that the transactions were conducted in the California market.

We therefore conclude that FERC must, on remand, include the CERS transactions when it determines whether refunds are warranted for sales in the Pacific Northwest spot market.

V

Finally, we must determine whether FERC was required to take into account evidence of market manipulation filed by the parties after the ALJ hearing. FERC permitted the Refund Proponents to submit new evidence of market manipulation that emerged after the ALJ's evidentiary proceeding. December 19, 2002 Order, 101 FERC ¶ 61,304 at 62,221 ("We will allow the movants and other parties in this proceeding to conduct additional discovery for the period January 1, 2000 to June 20, 2001."). The Refund Proponents argued that new evidence had emerged as a result of various investigations into the practices of Enron. *Id.* at 62,219. *See Lockyer*, 383 F.3d at 1015 (explaining many of Enron's manipulative tactics). Despite a great deal of new evidence submitted to FERC in the spring of 2003, however, FERC failed to take any of it into account, relying instead on the ALJ's factual findings from September 2001, which were made prior to the Enron revela-

tions. *See* June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,366-70. Regarding the new evidence, FERC's subsequent order denying rehearing stated merely: "In reaching its decision to terminate the proceeding, the Commission considered the complete record, including the material submitted in the March 2003 filings." November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,960.

In order for an agency to avoid making an arbitrary and capricious determination, it must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43, 103 S.Ct. 2856, 77 L.Ed.2d 443 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168, 83 S.Ct. 239, 9 L.Ed.2d 207 (1962)). An agency's ruling will be deemed arbitrary and capricious where the agency "entirely failed to consider an important aspect of the problem [or] offered an explanation for its decision that runs counter to the evidence before the agency." *Id. See also La. Pub. Serv. Comm'n v. FERC*, 184 F.3d 892, 898 (D.C.Cir.1999) (requiring FERC to examine submitted data); *Laclede Gas Co. v. FERC*, 997 F.2d 936, 948 (D.C.Cir.1993) (requiring FERC to provide adequate explanation). Moreover, an agency must account for evidence in the record that may dispute the agency's findings. *Universal Camera Corp. v. Nat'l Labor Relations Bd.*, 340 U.S. 474, 488, 71 S.Ct. 456, 95 L.Ed. 456 (1951) ("The substantiality of evidence must take into account whatever in the record fairly detracts from its weight.").

Given these requirements, FERC's failure to consider or examine the new evidence showing intentional market manipulation in California and its

potential ties to the Pacific Northwest was arbitrary and capricious. The Refund Proponents argue that the new evidence suggests, among other things, that: sellers of electricity in the Pacific Northwest were involved in schemes to withhold energy and to assist Enron in creating false congestion; Enron used markets outside of California in order to advance its tactics in California; Enron may have implemented fraudulent schemes outside California markets; and utilities in the Pacific Northwest violated posting requirements in transactions with Enron. Even assuming all of these transactions occurred in the California spot market, the fact that Pacific Northwest sellers were apparently involved in Enron's manipulation indicates that FERC must at least consider the possibility that the Pacific Northwest spot market was not, as the ALJ found, functional and competitive. June 25, 2003 Order, 103 FERC ¶ 61,348 at 62,366-67. FERC's findings, based on the record established by the ALJ in 2001, "that other factors related to supply and demand fundamentals contributed to the dramatic prices in the region," *id.* at 62,367, and that "no evidence of such 'lawlessness' has been shown with regard to any specific transaction in the Pacific Northwest spot market," November 10, 2003 Order, 105 FERC ¶ 61,183 at 61,966, must be reevaluated in light of this evidence.

Moreover, we reject the contention by the Refund Opponents that FERC need not consider the new evidence because FERC already is addressing market manipulation in separate proceedings focusing on misconduct. Not only did FERC fail to rely on this reasoning below, *see Laclede Gas Co.*, 997 F.2d at 945 (FERC order "must stand or fall on the grounds articulated by the agency in that order") (internal quotation marks omitted), but we have already held

that FERC's prosecutorial investigations cannot justify the denial of relief in contested adjudications before the Commission, *Pub. Utils. Comm'n*, 462 F.3d at 1048-51. Accordingly, we remand to permit FERC to examine this new evidence of market manipulation in detail and account for it in any future orders regarding the award or denial of refunds in the Pacific Northwest proceeding. FERC may also find it necessary to call for additional fact-finding if the record evidence of market manipulation is not sufficient to enable FERC to make a reasoned decision. In view of this remand, we offer no opinion on FERC's findings based on the record established by the ALJ.

VI

At this juncture we find it preferable to reserve judgment on other issues raised by the parties. As such, we decline to reach the merits of FERC's ultimate decision to deny refunds but urge the Commission to further consider its decision, on remand, in light of the related decisions of this court that followed FERC's final orders in the Pacific Northwest proceeding.

PETITION GRANTED IN PART; DENIED IN PART; REMANDED. Each party shall pay its own costs on appeal.

McKEOWN, Circuit Judge, concurring:

I concur in the opinion and the result, with the exception of the question of whether Puget Sound Energy is an "aggrieved party." Puget lacks standing because it was granted all the relief it sought (i.e., FERC granted price mitigation in the Pacific Northwest proceeding), and thus Puget is not "aggrieved" within the meaning of 16 U.S.C. § 825*l*(b). On this point, I agree with FERC's position. A party seeking

appeal must establish, at a minimum, "injury in fact" to a protected interest. *Shell Oil Co. v. FERC*, 47 F.3d 1186, 1200 (D.C.Cir.1995). Puget has not done so.

FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company (Complainant) v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange (Respondents), Docket Nos. EL00-95-004, EL00-95-005, EL00-95-019 and EL00-95-031

Investigation of Practices of the California Independent System Operator and the California Power Exchange, Docket Nos. EL00-98-004, EL00-98-005, EL00-98-018 and EL00-98-030

Puget Sound Energy, Inc. (Complainant) v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement (Respondents), Docket Nos. EL01-10-000 and EL01-10-001

Order Establishing Evidentiary Hearing Procedures, Granting Rehearing in Part, and Denying Rehearing in Part

(Issued July 25, 2001)

Before Commissioners: Curt Hébert, Jr., Chairman; William L. Massey, Linda Breathitt, Pat Wood, III and Nora Mead Brownell.

This order establishes the scope of and methodology for calculating refunds related to transactions in the spot markets operated by the California Independent System Operator Corporation (ISO) and the

California Power Exchange Corporation (PX) during the period October 2, 2000 through June 20, 2001. The Commission makes clear that transactions subject to refund are limited to spot transactions in the organized markets operated by the ISO and PX during the period October 2, 2000, through June 20, 2001, and include sales by public and non-public utilities into these markets. The order also establishes an evidentiary hearing proceeding in order to further develop the factual record in Docket No. EL00-95-031, *et al.*, so that refunds may be calculated. The order grants rehearing in part and denies rehearing in part of limited portions of earlier orders issued in this proceeding. In addition, the Commission establishes another proceeding before an Administrative Law Judge to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest from December 25, 2000 through June 20, 2001, and the calculation of any refunds associated with such charges.

Background

In an order issued August 23, 2000,[1] the Commission instituted formal hearing proceedings under Section 206 of the Federal Power Act (FPA) to investigate the justness and reasonableness of the rates for energy and ancillary services of public utility sellers into the ISO and PX spot markets, and also to investigate whether the tariffs, contracts, institutional structures, and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. In instituting an investigation into the reasonableness of the rates charged, however, the

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[1] *San Diego Gas & Electric Company, et al.*, 92 FERC ¶ 61,172 (2000), *reh'g pending* (August 23 Order).

Commission denied a request by San Diego Gas and Electric Company (SDG&E) contained in SDG&E's complaint against all sellers of energy and ancillary services into the ISO and PX markets subject to the Commission's jurisdiction, that the Commission impose a $250 price cap for sales into those markets. The Commission denied this request in the August 23 Order, on the grounds that SDG&E had not provided sufficient evidence to support an immediate seller's price cap.[2] The Commission established a refund effective date of 60 days after publication of notice in the *Federal Register* of the Commission's intent to institute a proceeding.[3]

The Commission issued an order on November 1, 2000 finding that the "electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain conditions."[4] The order noted that, "[w]hile this record does not support findings of specific exercises of market power, and while we are not able to reach definite conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power

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[2] 92 FERC at p. 61,606.

[3] *Id.* at p. 61,608.

[4] *San Diego Gas & Electric Company, et al.*, 93 FERC ¶ 61,121, at pp. 61,349-50 (2000), *reh'g pending* (November 1 Order).

when supply is tight, and can result in unjust and unreasonable rates under the FPA."[5]

To deal with these flaws, the November 1 Order proposed remedies intended to reduce over-reliance on spot markets in California, and attempted "to balance, on the one hand, holding overall rates to levels that approximate competitive market levels for the benefit of consumers, with, on the other hand, inducing sufficient investment in capacity to ensure adequate service for the benefit of consumers."[6] The November 1 Order changed the refund effective date contemplated in the August 23 Order from 60 days after publication of notice in the *Federal Register*, October 29, 2000, to 60 days after the date of SDG&E's complaint, October 2, 2000. The order also contained extensive discussion of the Commission's authority to direct refunds, for the periods both before and after the refund effective date, and concluded that the Commission is not authorized by the FPA to order refunds prior to the October 2 refund effective date. Several parties sought rehearing of this aspect of the November 1 Order.[7]

The Commission adopted many of the proposed remedies presented in the November 1 Order in an order issued December 15, 2000.[8] The December 15

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[5] *Id.* at p. 61,350.

[6] *Id.*

[7] *See, e.g.*, requests for rehearing of the California Electricity Oversight Board (Oversight Board), the Public Utilities Commission of the State of California (California Commission), PG&E, SoCal Edison, and the City of San Diego. Other determinations in the November 1 Order are also pending rehearing; these issues will be addressed in a future order.

[8] *San Diego Gas & Electric Co., et al.*, 93 FERC ¶ 61,294 (2000), *reh'g pending* (December 15 Order).

Order reiterated the earlier findings that the market structures and rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, had caused, and continued to have the potential to cause, unjust and unreasonable rates for short-term energy under certain conditions. The Commission, therefore, established a variety of remedies for the California wholesale electric markets, including, in part: (1) eliminating the requirement that the IOUs sell all of their generation into and buy all their energy needs from the PX so as to terminate the overreliance on spot markets; (2) adopting an advisory benchmark for assessing prices of long-term electric supply contracts in order to provide guidance for market participants to evaluate the reasonableness of long-term prices; (3) requiring market participants to preschedule 95 percent of their load prior to real time and penalizing those who do not, so as to eliminate market participants' chronic underscheduling with the ISO; and (4) requiring an independent governing board for the ISO.

As an interim measure, the Commission also established a $150/MWh breakpoint under which public utility sellers bidding above the breakpoint receive their actual bids, but are subject to monitoring and reporting requirements to ensure that rates remain just and reasonable, including the potential for having to pay refunds for prices charged above the breakpoint. The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001. In a separate order, the Commission established a settlement conference to facilitate forward

contracting by California investor owned utilities.[9] The Chief Administrative Law Judge convened discussions over five days in December 2000 and January 2001.

On January 23, 2001, the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convened a technical conference to develop a plan to replace the interim $150/MWh break-point price. Comments and reply comments on how to replace the interim break-point were filed with the Commission. In March 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market, and comments were filed on this proposal.

On March 9, 2001, the Commission issued an order addressing above-breakpoint transactions that occurred in January.[10] The March 9 Refund Order directed refunds from sellers for transactions occurring during Stage 3 Emergencies (when ISO reserves fell below 2.5 percent) above a proxy market clearing price ($273/MWh for that month), or alternatively, required sellers to submit additional cost or other justification for those transactions.[11] Parties requested rehearing of the March 9 Refund Order on many grounds. Among those were PG&E, SDG&E, and SoCal Edison's objections to the Commission's conclusion that it has no authority to order non-

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[9] *Forward Contracting by California Utilities*, 93 FERC ¶ 61,295 (2000).

[10] *San Diego Gas & Electric Co., et al.*, 94 FERC ¶ 61,245 (2001), *reh'g pending* (March 9 Refund Order).

[11] The Director of the Office of Markets, Tariffs and Rates issued notices announcing the proxy market clearing prices for the months of February, March, April, and May 2001 on March 16, April 16, May 14, and June 15, respectively.

public utility sellers to make refunds.[12] Additionally, numerous parties argued that price mitigation should apply during all hours.[13]

On April 26, 2001, the Commission issued its order adopting a prospective monitoring and mitigation plan for wholesale sales through the organized real-time markets operated by the ISO.[14] The Commission's plan, in pertinent part, enhanced the ISO's ability to coordinate and control planned outages during all hours; required certain sellers to offer the ISO all their available power in real time during all hours; established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anti-competitive bidding behavior in the real-time ISO markets during all hours; and established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's organized markets for real-time sales during system emergencies. In the April 26 Order, the Commission also established an inquiry into whether a price mitigation plan similar to the one for the California ISO's organized spot markets should be implemented in the Western Systems Coordinating Council (WSCC) and invited comment on how such a plan should be structured.

On June 19, 2001, the Commission expanded the price mitigation plan on rehearing, imposing curbs

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[12] *See March 9 Refund Order*, 94 FERC at p. 61,864.

[13] *See, e.g.*, Rehearings of California Commission, ISO, SDG&E, City of San Diego, County of San Diego, and PG&E. Other determinations in the March 9 Order are also pending rehearing; these issues will be addressed in a future order.

[14] *San Diego Gas & Electric Company, et al.*, 95 FERC ¶ 61,115 (2001), *reh'g pending* (April 26 Order).

not only on California ISO organized spot market sales during all hours, but also constraining prices for bilateral spot market sales throughout the WSCC for the period June 20, 2001 through September 30, 2002.[15] The order retained the use of a single price auction and must-offer and marginal cost bidding requirements when reserves are below 7 percent in the California ISO spot markets. Under the plan, the ISO market clearing price will also serve as a limit on prices in all other spot market sales in the WSCC during reserve deficiencies in California. Sellers in all spot markets in the WSCC will receive up to the clearing price without further justification. Sellers other than marketers will have the opportunity to justify prices above the market clearing price during reserve deficiency hours.

In the June 19 Order, the ISO market clearing price for reserve deficiency hours was also adapted for use in all Western spot markets when reserves are above 7 percent. Prices during non-reserve deficiency hours cannot, absent justification, exceed 85 percent of the highest hourly clearing price that was in effect during the most recent Stage 1 reserve deficiency period (*i.e.*, when reserves are below 7 percent) called by the ISO. These measures were applied to non-public utility sellers as well as public utilities to the extent they voluntarily sell power in the ISO or other WSCC spot markets or voluntarily use the ISO's or other Commission-jurisdictional interstate transmission facilities elsewhere in the WSCC.

In addition, the Commission announced that it would hold a settlement conference before an admin-

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[15] *San Diego Gas & Electric Company, et al.*, 95 FERC ¶ 61,418 (2001), *reh'g pending* (June 19 Order).

istrative law judge in order to resolve refund issues for past periods, among other things. The Commission's Chief Judge convened the conference from June 25 through July 9, 2001.

Chief Judge's Report and Recommendation

On July 12, 2001, the Chief Judge issued a report detailing his efforts to forge a settlement among the parties.[16] He explains that, while a global settlement agreement was not achieved, he believes that the negotiations were constructive. The Report finds that refunds owed to purchasers of electricity "amount to hundreds of millions of dollars, probably more than a billion dollars in aggregate sum," although not the $8.9 billion claimed by the State of California.[17] The Report mentions offers made by several sellers into the California market totaling $703.6 million, contingent upon reaching a global settlement of all issues.

According to the Report, efforts were hampered by incomplete data. The Chief Judge had requested the parties to provide, among other things: (1) the terms and prices of all forward contracts; (2) the amounts that California Department of Water Resources (DWR), the IOUs, and the ISO believe they owe to sellers; and (3) system load figures broken down by component. These data were not made available in their entirety. The Report also notes that the Pacific Northwest Parties did not have data on the amount of refunds due them nor balances past due from purchasers. For these and other reasons, the Chief Judge was not able to determine the total volume of

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[16] *San Diego Gas & Electric Company, et al.*, 96 FERC ¶ 63,007 (2001) (Report).

[17] *Id.*, slip op. at 3.

the spot market, nor were parties able to agree about the size of the market subject to the June 19 Order. The Report concludes that the differences between what the State and the sellers believe should be refunded raise material issues of fact. Further, the Report states, "[t]he appropriate numbers to calculate potential refunds involve factual disputes."[18] Thus, the Chief Judge recommends that the Commission order a trial-type evidentiary hearing limited to developing a factual record against which to apply a refund methodology.

The Chief Judge's recommended refund methodology would begin with the price mitigation approach set forth in the June 19 order, with several modifications for dealing with past, as opposed to future, transactions. Key differences include: (1) using actual, rather than hypothetical, heat rates; (2) using daily spot gas prices rather than monthly bid-week prices; (3) separating the state's gas market into northern and southern zones; (4) excluding emission costs from the market clearing price and treating them as an additional expense that may be subtracted from refund calculations; and (5) not using the 85 percent price ceiling for non-emergency hours, and instead recalculating each hour to determine the amount by which actual prices exceeded the mitigated price. The Chief Judge recommends retaining the 10 percent credit adder for sales after January 5, 2001, and not including interest unless the refund amount exceeds payments that are past due to the seller.

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[18] *Id.*, slip op. at 5.

Docket No. EL01-10-000

On October 26, 2000, Puget Sound filed a complaint in Docket No. EL01-10-000 petitioning the Commission for an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy and capacity under the Western Systems Power Pool Agreement, may sell energy or capacity in the Pacific Northwest's[19] wholesale power markets. Specifically, Puget Sound sought an order that prospectively capped the prices for wholesale sales of energy or capacity into the Pacific Northwest at a level equal to the lowest cap on prices established, ordered, or permitted by the Commission for wholesale purchases in, or wholesale sales of energy or capacity to or through the markets operated by the ISO or the PX. The December 15 Order declined to implement a region-wide price cap because it found that such a pricing methodology was impracticable given the market structure in the Pacific Northwest and because complainant had not met its burden of proof to justify such an action.[20] Puget Sound and others timely sought rehearing of the December 15 Order's determination not to impose a regional price cap or other mitigation.

On June 22, 2001, Puget Sound filed a motion to dismiss its complaint and a notice of withdrawal of its complaint and its subsequent rehearing request. Puget Sound explains that the June 19 Order satisfies its complaint because it implements price miti-

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[19] Puget Sound indicated that, as used in its complaint, the term "Pacific Northwest" has the meaning set forth in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14) (1994).

[20] *December 15 Order*, 93 FERC at p. 62,019.

gation measures throughout WSCC. Several parties filed answers to the motion. Bonneville Power Administration (Bonneville) states that the Commission must fully resolve the issues raised in the complaint regardless of whether it grants Puget Sound's motion, arguing that the focus on spot markets in the June 19 Order is not appropriate outside of California, where utilities rely on forward contracts. The City of Tacoma and Port of Seattle jointly filed an answer opposing the motion on the basis that dismissal would unduly prejudice parties outside of California that relied on the existence of the complaint, and arguing that the issues raised in the complaint are an integral part of market issues that the Commission is addressing in the SDG&E proceeding.

The City of Seattle (Seattle) filed an answer and a motion to intervene out-of-time in Docket No. EL01-10-000. Seattle contends that, although the June 19 Order satisfied Puget Sound's complaint, the Commission should keep the proceeding open because non-California market participants have paid prices that are unjust and unreasonable, and because retaining the proceeding would permit the Commission greater flexibility in determining the scope and effective date for refunds.

The Washington Commission and the Attorney General of Washington state several principles that they believe should guide the Commission's determination of whether and how to order refunds for and by the utilities in the Pacific Northwest, *i.e.*, that refunds should be symmetrical as to all purchases and sales, and unbiased with respect to acquisition strategies. In addition, the Attorney General of Washington moves to intervene out-of-time.

On June 22, 2001, unaware of Puget Sound's motion filed on the same day, the Commission issued an order clarifying the June 19 Order to indicate that parties in the settlement proceeding were not limited to settling only California-related matters, but could also discuss settling past accounts related to sales in the Pacific Northwest. The Chief Judge's Report stated that there was little time to address the issues raised by the parties in Puget Sound's proceeding and noted that they did not have data on unpaid balances nor on refunds due them.

Discussion

A. *Procedural Matters*

A number of entities filed late motions to intervene in this proceeding, as described below. On December 28, 2000, the Southern California Water Company (SoCal Water) filed an intervention in Docket No. EL00-95-000, *et al.*[21] On January 30, 2001, the New Mexico Regulation Commission (New Mexico Commission) filed a motion to intervene out-of-time in Docket No. EL00-95-000, *et al.*, raising no substantive issues. On February 9, 2001, the Public Utilities Commission of Nevada (Nevada Commission) filed a motion to intervene out-of-time with comments encouraging recognition of the regional scope of the crisis. On April 9, 2001, the American Public Power Association (APPA) filed a motion to intervene and request for rehearing of the March 9 Refund Order. On July 12, 2001, the Washington Utilities and Transportation Commission (Washington Commission) filed a motion for clarification of its intervenor status, or, in the alternative, a motion to intervene

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[21] SoCal Water subsequently requested rehearing of the December 15 Order.

out-of-time in Docket No. EL00-95-031, *et al.* Finally, on July 17, 2001, the People of the State of California, *ex rel.* Bill Lockyer (Attorney General of California) moved to intervene out-of-time in Docket No. EL00-95-031, *et al.*

In addition, on December 26, 2000, the Oregon Public Utilities Commission (Oregon Commission) filed a late motion to intervene in Docket No. EL00-10-000, stating that it had not yet developed a position on Puget Sound's complaint. On January 16, 2001, the Washington Commission also filed a late motion to intervene in that proceeding with comments in support of Puget Sound's request for rehearing. The City of Seattle (Seattle) and the Attorney General of Washington filed motions to intervene out-of-time in Docket No. EL01-10-000 on July 9, 2001.

The Commission ordinarily does not permit late interventions after an order has been issued, particularly for the purpose of requesting rehearing.[22] However, over the course of the SDG&E proceeding, the Commission has expanded the scope of its focus from just California to include the entire Western interconnect and also to implicate wholesale spot market transactions of non-public utilities. We find good cause, therefore, to grant the untimely, unopposed motions to intervene in Docket No. EL00-95-000 filed by the entities described above.[23]

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[22] *See, e.g., Southern Company Services, Inc.*, 92 FERC ¶ 61,167 (2000); *Consolidated Edison, Inc. and Northeast Utilities*, 92 FERC ¶ 61,014 (2000), *order denying reh'g*, 94 FERC ¶ 61,079 (2001).

[23] In the May QF Order, we intended, but inadvertently failed, to grant the timely, unopposed motion to intervene of Carson Cogeneration Company, LP, Mojave Cogeneration Com-

These intervenors must accept the record as it had developed as of the date of their intervention, and their participation in this proceeding is limited to the issues that arose after the date each requested to participate in these proceedings. Thus, the request for rehearing of the December 15 Order filed by SoCal Water will be dismissed because it was not a party as of the date that order was issued. Similarly, APPA's request for rehearing of the March 9 Refund Order will be dismissed because it was not a party as of the date that order was issued.

In view of the interest of the Oregon Commission, the Washington Commission, the Attorney General of Washington, and Seattle, and the absence of any undue prejudice or delay, we will grant their untimely, unopposed motions to intervene. We also clarify that the companies listed individually in the caption of the March 9 Refund Order are respondents, and thus, under Rule 102 of the Commission's Rules of Practice and Procedure,[24] are parties in the SDG&E proceeding.

B. *Scope of Refunds*

1. *The Commission's Retroactive Refund Authority*

a. *Introduction and Summary*

In the Commission's November 1 Order, we concluded that the FPA and the weight of court precedent strongly suggest that refunds prior to October 2, 2000 are impermissible under the circumstances of

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pany, LP, O.L.S. Energy-Camarillo, O.L.S. Energy-Chino, and PE Berkeley, Inc. (collectively, QF Petitioners) filed in Docket No. EL00-98-000, and the untimely, unopposed motion to intervene of Berry Petroleum Company in Docket No. EL00-95-020. We do so in this order.

[24] 18 C.F.R. § 385.102(c)(2) (2001).

this case, which arose in a Section 206 complaint context. In the December 15 Order, we addressed prospective remedies necessary to correct market dysfunctions and to assure just and reasonable rates, but did not address the comments on retroactive refund authority. We do so here to clarify our statutory refund authority and the scope of refunds subject to the hearing being ordered below.

We have again examined the statute, its legislative history and the case law, and have analyzed the arguments raised on this issue in comments on and requests for rehearing of the November 1 Order. We conclude that FPA Section 206 does not permit the Commission to require refunds of unjust and unreasonable rates charged prior to a date 60 days after the filing of a complaint or 60 days after the initiation of a Commission investigation on its own motion. To order such refunds would contravene explicit refund limitations that Congress put in FPA Section 206. While that refund authority can be expanded in limited circumstances (*e.g.*, where sellers have charged a rate other than the filed rate or where an appellate court has found that the Commission committed legal error), as discussed below, none of those circumstances is present here. Thus, in the specific situation present here, we cannot order refunds of unjust and unreasonable rates charged prior to October 2, 2000, the start of the refund effective period.[25] Accordingly, we will deny the requests for rehearing of the November 1 Order challenging the order's find-

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[25] The FPA, with one exception, permits refunds only for a period of 15 months after the refund effective date. The exception is that if a public utility engages in dilatory behavior in a Section 206 proceeding, the Commission can extend the refund period beyond 15 months from the refund effective date.

ings about the Commission's retroactive refund authority, *i.e.*, refund authority prior to October 2, 2000.[26]

b. *The Commission's Retroactive Refund Authority*

Several parties argue that the Commission's statutory duty to protect consumers and its broad legal and equitable authority to do so requires that the Commission remedy unjust and unreasonable rates for the period prior to October 2 by ordering refunds.[27] Other parties agree with the November 1 Order's conclusion that the Commission has no legal authority to grant refunds for overcharges prior to October 2.[28] As discussed below, we conclude that the Commission lacks the authority to order retroactive refunds of unjust and unreasonable rates charged prior to October 2.

i. *Sections 205 and 206 of the FPA*

Comments

Several parties argue that because Sections 205 and 206 of the FPA require that the Commission ensure just and reasonable rates, the Commission, having found the pre-October 2 rates to be unjust

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[26] To the extent parties raise the same arguments on rehearing of the December 15 Order, we similarly deny rehearing.

[27] *E.g.*, Comments filed November 22, 2000, by Southern California Edison Company (SoCal Edison), Pacific Gas and Electric Company (PG&E), SDG&E, City of San Diego, County of San Diego, California Commission, TURN/UCAN, California State Senator Morrow, Oversight Board, California Legislature, San Diego Association of Governments.

[28] *E.g.*, Comments of DOE, Enron, Calpine, Dynegy, PPL EnergyPlus, Reliant, Duke Energy, Williams, IEP, WPTF, Xcel Energy. DOE also comments that Congress should examine whether to amend the FPA to provide the Commission with authority to require retroactive refunds in the future.

and unreasonable, is obligated to order refunds for that period. They further argue that the Commission is not prohibited from ordering retroactive refunds of market-based rates.

Other parties argue that neither Section 205 nor 206, on its face, grants the Commission authority to order retroactive refunds. Thus, they maintain that the Commission may not order refunds for the pre-October 2 period.

Commission Determination

A number of parties confuse the just and reasonable standard with the authority to order retroactive refunds of unjust and unreasonable rates. Whether rates are unjust and unreasonable is a separate issue from whether the Commission is authorized under the statute to order refunds retroactively. Under FPA Section 206, if the Commission finds that rates no longer meet the just and reasonable standard, the Commission has a statutory obligation to fix a new rate or to fix practices "to be thereafter observed."[29] In amending FPA Section 206, Congress did not give the Commission authority to modify unjust and unreasonable rates retroactively. As discussed in the Appendix to the November 1 Order, when Congress passed the FPA in 1935, it excluded a provision from the original bill that would have authorized the Commission to retroactively order reparations for charges found to be excessive or unreasonable if a complaint were filed within two years from the date of payment. Courts later concluded that this exclusion showed that Congress intended that the Commission have authority to only grant relief in a Section 206 proceeding prospectively from the date of its

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[29] 16 U.S.C. § 824e(a) (1994).

order. *See, e.g., City of Bethany v. FERC*, 727 F.2d 1131 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

As a result, Congress added limited refund authority to Section 206 in the Regulatory Fairness Act of 1988 (RFA). S. Rep. No. 491, 100th Cong., 2d Sess. 3-4 (1988), *reprinted in* 1988 U.S.C.C.A.N. 2685. As amended, FPA Section 206 restricts the Commission's authority to establish a refund effective date to no earlier than 60 days after the date that a complaint is filed or the Commission initiates an investigation. Therefore, Section 206 does not permit retroactive refund relief for rates covering periods prior to the filing of a complaint or the initiation of a Commission investigation, even if the Commission determines that such past rates were unjust and unreasonable.

ii. *The Filed Rate Doctrine and the Rule Against Retroactive Ratemaking*

Parties urging retroactive refunds make several arguments concerning the filed rate doctrine and its corollary, the rule against retroactive ratemaking. Taken together, the doctrine and its corollary stand for the propositions that a utility may charge only those rates that are on file with and approved by the Commission, and conversely that the Commission may not alter those filed rates retrospectively. The arguments against the application of the doctrine and its corollary can be condensed to the following: the filed rate doctrine does not apply to market-based rates; the Commission's past market-based rate authorizations in California markets constituted legal error; and the rates charged were inconsistent with sellers' filed rates. According to these parties, the filed rate doctrine does not preclude retroactive refunds in these specific circumstances.

(a) *Whether the Filed Rated Doctrine Applies to Market-Based Rates*

Comments

Oversight Board and County of San Diego argue that the filed rate doctrine does not apply to market-based rates because the actual rates have not been filed with the Commission, and because prices fluctuate with the market. Accordingly, they assert that there is no fixed rate on file on which buyers and sellers could rely, and which would prohibit retroactive refunds.

County of San Diego contends that several principles underlying the filed rate doctrine and the rule against retroactive ratemaking do not apply to market-based rates and, thus, are not dispositive in this case. Specifically, it contends that: the principle that regulated companies can charge only those rates of which the agency is cognizant does not apply to these facts, because the Commission no longer receives prior notice of actual market-based rates; the nondiscrimination principle does not apply, because market-based pricing allows utilities to sell at different rates to different customers; and the principle of predictability is not applicable, because the market, not a fixed rate or published formula, determines prices. Instead, County of San Diego asserts that another principle underlying the filed rate doctrine – the principle of reasonable expectations – is dispositive. It contends that market participants and the Commission clearly expected that competitive forces would be adequate to restrain prices in the California markets to just and reasonable levels, whereas sellers had no legitimate or reasonable expectation of being able to demand unjust and unreasonable prices due to an absence of competition. Thus, it argues that the reasonable

expectations rationale underlying the filed rate doctrine supports a requirement for refunds in this case.[30]

Commission Determination

Under the FPA, Sections 205 and 206 are the statutory foundation for the filed rate doctrine and the rule against retroactive ratemaking. FPA Section 205(c) states: "Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate . . . schedules showing all rates and charges subject to the jurisdiction of the Commission . . . ." This provision does not distinguish between cost-based and market-based rates. Nor does the provision require that the Commission receive prior notice of market-based rates, as San Diego contends.[31]

As the Court of Appeals for the District of Columbia Circuit recently recognized, "[t]he Commission has held that traditional utilities and power market-

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[30] Comments of County of San Diego at 11-13.

[31] Contrary to County of San Diego, the rationales underlying the filed rate doctrine apply to market-based rates. First, San Diego is incorrect that Section 205(c) requires prior notice of the actual market-based, numerical rates. In addition, the fact that a market-based tariff or rate schedule is on file instead of a specific, quantified rate is not dispositive, so long as buyers know (or can know by examining the Commission's public files) the type of rates authorized for each seller. The principle of predictability requires that the parties know the type of rate being used, not necessarily the exact numerical rate. When a buyer knows market-based rates are being used, the buyer can predict that rates will fluctuate with differing conditions, and can plan accordingly. That is all that is required. Thus, the filed rate doctrine and its corollary, the rule against retroactive ratemaking, apply to market-based rates.

ers who engage in market-based rate transactions are required to file quarterly reports summarizing transactions and that these reports satisfy the filing requirements of § 205(c),"[32] and the court did not question the Commission's judgment in this regard. Consequently, the Commission's current procedures for quarterly filing of market-based transactions satisfy the Section 205(c) filing requirements for market-based rates. The market-based rates at issue here were on file with and approved by the Commission. Second, in response to Section 206 complaints and our own investigation, the December 15 Order implemented a number of structural changes to the existing California market mechanisms to eliminate those features that were creating the possibility of unjust and unreasonable rates. The structural changes satisfied our Section 206(a) obligation to determine the just and reasonable provisions to be thereafter in force.

We find San Diego's reasonable expectation principle not to be a tenet of the filed rate doctrine, but merely a restatement of our statutory duty to set just and reasonable rates. San Diego's effort to engraft this principle into the filed rate doctrine seeks to evade the distinction, noted above, between our delegated authority under Section 206 to find that existing rates are unjust and unreasonable and the statutory restriction on refunds in such cases. The filed rate doctrine cannot give us greater refund authority than that allowed in the FPA, and therefore we reject San Diego's claim that its reasonable expectation

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[32] *Power Co. of America, L.P. v. FERC*, 245 F.3d 839, 846 (D.C. Cir. 2001).

rationale supports a requirement for refunds in this case.[33]

To conclude, the filed rate doctrine applies to the market-based rates at issue here, and the statutory limitations on our refund authority prohibit retroactive refunds.

(b) *Legal Error*

Comments

Some parties argue that the Commission's market-based rate authorizations relied on determinations that the markets were competitive, but that the markets have now been shown not to be competitive. They argue that, by allowing market-based rates in markets that were not workably competitive, the Commission committed legal error, which constitutes a basis for the Commission to order retroactive refunds to correct its mistakes.

Commission Determination

The parties' reliance on a "legal error" theory is flawed. First, we disagree that the Commission committed legal error by allowing market-based rates to remain in effect in California. Rather than eliminate market-based rates entirely, as these parties seem to advocate, the Commission reasonably sought to correct the flaws that could cause unjust and unreasonable rates in certain conditions. The December 15 Order contained a number of remedial

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[33] *See Towns of Concord, Norwood and Wellesley v. FERC*, 955 F.2d 67, 73 (D.C. Cir 1992) (rejecting argument that assumes a "'right' ceases to exist unless it is backed up by a remedy, that the Commission's denying refunds equals the Commission's authorizing the utility to violate the filed rate doctrine . . . . This is good advocacy but the case cannot be decided on any such theory.").

measures designed to correct those flaws. As found by the Ninth Circuit, "FERC's actions, taken together, appear to be fully consistent with § 206(a)."[34] Thus, we disagree that the Commission's approach can be considered to constitute legal error.

Second, while we recognize that retroactive refunds can be ordered where a court reverses a non-final Commission decision on the merits,[35] the parties have challenged the Commission's original decisions to grant market-based pricing authority to various applicants. Those orders have, however, become final and non-appealable under FPA Section 313, and thus courts would lack jurisdiction to review those decisions. Third, to the extent that the parties are raising questions about the operation of specific sellers' exercise of market-based pricing, those cases must proceed under Section 206, as, in fact, this case does. In a Section 206 complaint, our refund authority is confined by the statutory language to commence 60 days after the complaint was filed, or October 2, 2000 in the instant case. We do not see how a court could

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[34] *In re: California Power Exchange Corp.*, 245 F.3d 1110, 1121 (9th Cir. 2001).

[35] *See United Gas v. Callery Properties*, 382 U.S. 223, 229 (1965) (while the Commission has no power to make reparation orders, its power to fix rates being prospective only, it is not so restricted where its order, which never became final, has been overturned by a reviewing court); *Reynolds Metals Co. v. FERC*, 777 F.2d 760, 763 (D.C. Cir. 1985) (same). *See also Tennessee Valley Mun. Gas Assn. v. FPC*, 470 F.2d 446, 453 (D.C. Cir. 1972) (granting of refunds did not violate anti-reparations language in the statute which was designed to protect established expectations under legally established rate schedules. One "cannot claim justifiable reliance or protectable expectations based on [Commission] action which was illegal").

find legal error in our decision to follow the statutory requirement.

(c) *Whether the Rates Charged Were Inconsistent with a Competitive Market Rate*

Comments

Several parties argue that market-based rates are just and reasonable only if the market is sufficiently efficient and sufficiently free from the ability of market participants to exercise market power so that actual prices charged in the marketplace approximate the "true" market price, *i.e.*, the price that would obtain in a hypothetically "fully competitive" and efficient market. The parties argue that there was an implied condition in the seller authorizations,[36] or that the market power conditions of market-based rate authorizations are analogous to an implied contract between seller and buyer,[37] such that if a seller were found, after-the-fact, to have exercised market power, this would be deemed a violation of the seller's market rate tariffs and subject the seller to retroactive refund liability. They contend that the exercise of market power resulted in prices well above what would prevail in a workably competitive market, and, accordingly, prices charged by sellers during the summer of 2000 are contrary to the filed rate authorizations, and refunds should be ordered.[38]

The parties further argue that the Commission may order retroactive refunds where the rates charged exceed the filed rate or for violations of the

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[36] *E.g.*, Comments of PG&E; Rehearing of PG&E.

[37] Comments of City of San Diego.

[38] These parties do not define a "fully competitive" or "workably competitive" market.

conditions of sellers' market-based rate authority. In support, they cite cases in which the Commission ordered: disgorgement of profits for a period prior to the initiation of the Commission's complaint as a sanction against a public utility that violated the standards of conduct that were contained in its market-based tariff; refunds for monies illegally recovered through a fuel adjustment clause; refunds when the utility charges impermissible costs through a filed formula rate; and disgorgement of some revenues resulting from a transaction that lacked necessary Commission authorization.[39]

Other parties assert that the rates charged this summer comport with the filed rate doctrine, that there is no evidence that sellers charged rates that were not in compliance with the tariffs on file, and that sellers must be able to rely on the finality of filed rates.

Commission Determination

We agree that the Commission may take retroactive action to address circumstances where a seller did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs.[40] However, it has not been demonstrated that

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[39] *E.g.*, Comments of PG&E, Oversight Board, City of San Diego, California Commission, SDG&E, County of San Diego; Rehearings of SDG&E, PG&E, Oversight Board.

[40] For example, in *Washington Water Power Co.*, 83 FERC ¶ 61,282 (1998), the Commission imposed sanctions for violations by Washington Water Power Company (WWP) and its power marketer affiliate Avista Energy, Inc. (Avista), of Avista's market-based rate order, specifically the affiliate conduct, OASIS and Standards of Conduct requirements. Avista was required to disgorge its profits from the power sale at issue, and Avista's market-based rate authority was suspended prospec-

any conditions or limitations of sellers' market-based rate tariffs have been violated. The conditions hypothesized by the parties are not evident from the market-based rate schedules or our orders. Thus, there is no basis for finding that the sellers acted inconsistently with Commission-filed tariffs or with specific requirements in their filed rate authorizations. To the extent the Commission found that changed conditions in California created the opportunity for unjust and unreasonable rates, it remedied those problems prospectively. If it finds that refunds are appropriate, it can order refunds in accordance with the RFA refund effective date.

iii. *Whether Sellers' Market-Based Rate Authorizations Were Provisional, Making the Rates Being Charged Subject to Retroactive Adjustment*

Comments

The California Commission argues that the Commission may order refunds without violating the filed rate doctrine or the corollary rule against retroactive ratemaking if buyers and sellers were on notice that the rates being charged were "provisional," and might be subject to adjustment in the future. It argues that the Commission's early California electric restructuring orders contained qualifications that indicate that these decisions were provisional, and which warn that the structure and dynamics of the markets and their resulting rates were subject to adjustment or revision. It cites the November 1996 order (authorizing the establishment of the PX and the ISO) as characterizing the Commission's determination as "conditional" and "preliminary." *See*

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tively for six months with respect to any power sale requiring the use of WWP's transmission system.

PG&E, et al., 77 FERC ¶ 61,204, at p. 61,793 (1996). It also cites the October 1997 order authorizing the PX and the ISO to commence operations, *PG&E, et al.*, 81 FERC ¶ 61,122, at p. 61,435 (describing such authorization as "interim" and "conditional"); the December 1997 order authorizing the transfer of operational control of jurisdictional facilities, *PG&E, et al.*, 81 FERC ¶ 62,210, at p. 64,473 (expressly reserving the right to "place further conditions on the transfer for good cause shown"). Thus, according to the California Commission, there was nothing certain on which buyers and sellers could have justifiably relied. Accordingly, there was no predictability as to what rates were being protected by the filed rate doctrine and rule against retroactive ratemaking.[41]

Oversight Board argues that the controversy over the high prices during the spring and summer of 2000 effectively put sellers on notice that their rates would be challenged, *i.e.*, no reasonable seller would believe that their rates would go unchallenged.

Commission Determination

While it is correct that the Commission issued conditional orders on the restructuring and indicated that future changes might be made, the conditions went to the restructuring and the market rules, which were at that time not entirely finalized and were being implemented in phases. The Commission did not make changes to the individual sellers' market rate authorizations. The individual market-based rate applications were not made subject to a retroactive refund obligation when accepted, and the applicants had no reasonable expectation of such an obli-

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[41] *See also* Comments of PG&E, SDG&E.

gation.[42] The orders give no indication that the Commission would consider retroactively changing rates. The conditions in the authorizations were very explicit, and indicated only that the Commission would revoke market rates if the seller acquired market power, not that it would retroactively change the rates.[43] Further, nothing in the restructuring or market rule orders indicates that the Commission was placing such a condition on sales into the ISO or PX.

Moreover, the mere existence of uncertainty or expectation of future controversy concerning sellers' rates would not serve to establish a *de facto* refund effective date for purposes of retroactive refunds. As discussed above, the establishment of a refund effective period is governed by the statute. As the instant matter arose from a complaint under Section 206, we must look to that provision. Its terms specifically provide that the refund effective date is triggered by the filing of a complaint or the initiation of an investigation by the Commission. Section 206 does not provide for constructive notice. The refund effective date of October 2, 2000 is consistent with the statutory framework.

iv. *Section 309 Authority*

Comments

Several parties argue that there is substantial evidence that sellers were unjustly enriched by ISO and

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[42] By comparison, with respect to costs collected through fuel adjustment clauses, acceptance of Commission authority to adjust such charges after-the-fact is a condition of acceptance of the fuel adjustment clause filings.

[43] *E.g., Louisville Gas and Electric Company*, 62 FERC ¶ 61,016, at p. 61,143 n.15 (1993).

PX prices above competitive levels because sellers exercised or benefitted from the exercise of market power. They cite the Staff Report and the market monitoring reports prepared by California's independent market monitors.[44] They argue that the Commission has broad authority under Section 309 of the FPA to restore the status quo and prevent unjust enrichment. In effect, they argue that Section 309 gives the Commission retroactive refund authority for past unjust and unreasonable rates. They cite *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 158 (D.C. Cir. 1967) (upholding decision to backdate a hydro license, and thus require back payments from a licensee who had failed to obtain its license prior to constructing hydro facilities); *Mesa Petroleum Co. v. FPC*, 441 F.2d 182 (5th Cir. 1971) (requiring a gas supplier to pay a purchaser the difference between what the purchaser would have paid under its contract with the supplier and the amounts it actually had to pay for replacement gas when the supplier abandoned the contract without Commission approval); and *Louisiana Public Serv. Comm'n v. FERC*, 174 F.3d 218, 224 n.6 (D.C. Cir. 1999) ("[t]he Commission's authority to order refunds of amounts improperly collected in violation of the filed rate derives from FPA § 309."). These parties urge the Commission to use FPA Section 309 to order equitable relief that requires sellers to repay buyers the profits

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[44] *See, e.g.*, Comments of SoCal Edison, *citing* the study attached as Exh. A to its comments (Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000" (November 21, 2000)).

above competitive levels that the sellers received as a result of the exercise of market power.[45]

Oversight Board further asserts that Section 4(i) of the Communications Act is analogous to Section 309 of the FPA and that a court interpreted Section 4(i) as conferring upon the Federal Communications Commission (FCC) authority to order retroactive refunds, even though Sections 204 and 205 of the Communications Act, which it states are analogous to Sections 205 and 206 of the FPA, do not authorize the FCC to order retroactive refunds.

SDG&E argues that the imposition of sanctions by the Commission may provide the only means to remedy abuses of market power by sellers. It expresses concern that courts may rule that antitrust claims and state law claims alleging injury due to unlawfully high prices – even if those prices are shown to have resulted from price-fixing collusion by sellers – would be preempted by the filed rate doctrine. It asserts that the Commission should investigate whether, and which, sellers have engaged in manipulative conduct including, but not limited to, the sub-

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[45] Comments of PG&E, SoCal Edison; Rehearings of SDG&E, PG&E. SoCal Edison cites Order No. 637-A, in which the Commission expressly did not make natural gas transportation rates subject to refund because it could rely on its authority to afford relief pursuant to Section 16 of the Natural Gas Act (NGA), which is analogous to Section 309 of the FPA. *See Regulation of Natural Gas Transmission Services and Regulation of Interstate Natural Gas Transportation Services, FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000* ¶ 31,091 (2000), *order on reh'g*, 91 FERC ¶ 61,191 (2000), *appeal pending sub nom. Process Gas Consumers v. FERC*, No. 00-1217 (D.C. Cir. filed May 26, 2000). SoCal Edison argues that the Commission could apply Section 309 similarly in this case.

mission of phantom schedules to create apparent transmission congestion, the export and later re-importation of power to evade PX and ISO price caps, and the aggregation of significant amounts of supply from multiple sources by one scheduling coordinator for composite bidding in the wholesale markets. According to SDG&E, sellers who engage in such market abuse should be sanctioned by disgorgement of profits that resulted from such abuse.

Oversight Board argues that the Commission's failure to address the legal issue of refund authority for the period prior to October 2, 2000 creates uncertainty and prevents resolution of the issue on appellate review.

Commission Determination

The remedial authority under Section 309[46] is designed to fill in gaps where the FPA is silent, not to rewrite the explicit Congressional delegations of authority and explicit limitations on that authority. Section 309 and similar provisions "authorize an agency to use means of regulation not spelled out in detail, provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act." *Niagara Mohawk*, 379 F.2d at 158. Here, as we have reiterated, Congress explicitly delineated the extent of our refund authority under FPA sections 205 and 206. We do not read Section 309 to permit us to go beyond that delegation.

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[46] FPA Section 309 states in pertinent part: "The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this Act."

Courts interpreting FPA Section 309, and its counterpart NGA Section 16, have indicated that "[b]oth sections are of an implementary rather than substantive character. . . . These sections merely augment existing powers conferred upon the agency by Congress, they do not confer independent authority to act." *New England Power Co. v. FPC*, 467 F.2d 425, 430-31 (D.C. Cir. 1972), *aff'd*, 415 U.S. 345 (1974).[47] Contrary to what the parties here seem to suggest, Section 309 is not an independent source of authority that allows the Commission to expand its authority beyond that allowed in its governing statutes:

> The substantive provisions of the [NGA] contemplate certain procedures, as incident to the functions provided. The range of permissible procedures must be derived from these sections, sections like Section 4 and 5 of the [NGA], and the functions they describe. Section 16, which uses a broad generality of "necessary and appropriate" that is not rooted in a function, cannot enlarge the choice of permissible procedures beyond those that may fairly be implied from the substantive sections and the functions there defined.

Mobil Oil Corp. v. FPC, 483 F.2d 1238, 1257 (D.C. Cir. 1973). The parties here seek not to introduce new procedures under FPA Section 309, but to enlarge the substantive refund limitations in Section 206 by expanding the refund period. If Section 309 cannot be used to enlarge the permissible procedures under

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[47] *Accord, e.g., McCombs v. FERC*, 705 F.2d 1177, 1184-85 (10th Cir. 1980); *Murphy Oil Corp. v. FPC*, 431 F.2d 805, 810 (8th Cir. 1970).

the FPA, as *Mobil* found, then it surely cannot be used to expand the substantive provisions of the Act.

Oversight Board's reliance on *New England Tele phone & Telegraph Co. v. FCC*[48] is misplaced. Although the Communications Act ("CA") contains similar provisions to FPA Sections 205, 206, and 309, the statutory language differs in several respects as does the underlying regulatory approaches of the two Acts. The FCC in that case addressed different circumstances from those we face, in particular in that case the FCC used its powers to "prescribe rates of return," rather than to prescribe overall rates.[49] That prescription was upheld under CA Section 4(i), analogous to FPA Section 309, despite a finding that "[CA] Section 205 does not authorize the Commission to prescribe rates of return," *Nader*, 520 F.2d at 203, as being consistent with the purposes of CA Section 205. *Id.* at 204-05.

Importantly for this question, at the same time it prescribed a rate of return, the FCC stated that "the filing of a tariff designed to produce a rate of return in excess of [the allowed amount] is *prima facie* unlawful." *Id.* at 205 n.25. This, the Court stated, meant "the Commission retains full latitude to order refunds on all other grounds," except that the allowed rate of return was too high. *Id.* Subsequently, when the FCC found that AT&T had earned a rate of return in excess of the allowed amount and ordered refunds, the court upheld this determination as "a straightforward and legitimate means for the Com-

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[48] 826 F.2d 1101 (D.C. Cir. 1987), *cert. denied*, 490 U.S. 1039 (1989).

[49] 826 F.2d at 1109-10 and 1104-05; *Nader v. FCC*, 520 F.2d 182, 204 (D.C. Cir. 1975).

mission to enforce its 1976 rate-of-return prescription."[50] The Court found that this did not represent retroactive ratemaking "because the carriers' obligations were set prospectively in 1976, when the Commission forbade AT&T from earning more than 10%," the allowed rate of return.[51] As the FCC had set the 1976 rate of return prescription under its CA Section 4(i) authority, it "properly exercised its authority under Section 4(i) to remedy the violation by ordering rate reductions in the amount of AT&T's excessive earnings in 1978." *Id.* at 1109.

There is no parallel in the instant case. The Commission did not use its FPA Section 309 power to establish individual market pricing authorizations. Nor did it set an objective standard against which market pricing standards would be measured or indicate that any price above that standard would be considered *prima facie* excessive. Thus, none of the elements that allowed the FCC to use its CA Section 4(i) power to order refunds are presented here. Consequently, use of FPA Section 309 as a means now to order retroactive refunds cannot be justified in face of the statutory limitations found in Section 206.

c. *Equitable Relief*

PG&E proposes that, as an equitable alternative to price adjustments and refunds for the past period, the overcharges occurring prior to October 2 be quantified and amortized over a period of time, with the costs to be recovered from power sellers in California through an adjustment to their future bids in the ISO and PX markets. PG&E maintains there are precedents in the gas and electric industry for doing

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[50] *See* 826 F.2d at 1111.

[51] *Id.* at 1108.

so. PG&E notes that the Commission's restructuring of the natural gas pipeline and electric industries permitted recovery of costs resulting from a fundamental change in market rules and regulatory policies. According to PG&E, a finding that the overcharges of the summer relate to flawed market rules and regulatory policies rather than tariff violations makes it equally appropriate that there be recovery of the unjustly incurred costs for buyers of power in California. It asserts that the profound changes in industry rules, brought on by the fundamental shift in regulatory policy in California and at the Commission, required that the California IOUs buy power on the volatile spot market. They were required to participate in the new industry structure, and they have incurred unprecedented costs as a result, according to PG&E.

IEP contends that market participants cannot manage or hedge the risks associated with the November 1 Order's equitable solutions proposal and that the proposal only invites litigation and exacerbates uncertainty that will harm California. If the Commission retains the equitable solutions proposal, IEP argues that the Commission must clarify that it is a temporary transition device only and that it will end on a date certain and not be subject to reopening.

Commission Determination

The electric and gas restructuring cases cited by PG&E are different from this case. They involved a change in regulatory scheme and allowed utilities to recover costs incurred under the pre-existing regulatory scheme. Order No. 637-A, cited by SoCal Edison, is also different from this case, because the equitable relief provided for in the rule under Section 16 of the Natural Gas Act pertains to remedies for

specific violations. Similarly, other cases cited by the parties involved sanctions for violations of explicit statutory commands.[52]

2. *Refund Liability Should Apply to all Sellers of Energy in California*

The Commission has determined that all sellers of energy in the California ISO and PX spot markets should be subject to refund liability for the period beginning October 2, 2000.[53] We have decided to extend refund liability to public and non-public utility sellers based on our review of the controlling law, the involvement of both types of sellers in the California centralized ISO and PX spot markets, and the equities of the situation. Non-public utility sellers as well as public utility sellers of electric energy in those California markets contributed to and benefitted from the dysfunctions that offered the possibilities for the market abuse under certain conditions, on which the call for refunds are based. In these circumstances, as discussed below, we conclude that although we do not have direct regulatory rate authority over power sales by non-public utilities, we do have authority to order them to abide by the market

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[52] *Niagara Mohawk* (constructing a hydro facility without a license), *Mesa Petroleum* (abandonment without prior Commission approval), and *Louisiana Public Serv. Comm'n* (collections in violation of filed rates).

[53] While the Commission in other orders and in other contexts has stated that it does not have jurisdiction over non-public utilities under Sections 205 and 206 of the FPA, we have re-examined our authority in the particular circumstances presented here: a centralized single clearing price auction that sets wholesale prices for both public utilities and non-public utilities, pursuant to market rules set by this Commission and administered by public utilities subject to this Commission's jurisdiction (the California ISO and PX).

rules we have established and to make refunds of unjust and unreasonable rates for sales pursuant to those market rules. Accordingly, PG&E's, SoCal Edison's, and SDG&E's requests for rehearing of the March 9 Refund Order seeking refund liability for non-public utilities will be granted.

a. *Statutory Framework*

Analysis of the Commission's authority begins, as it must, with the FPA statutory language. The refund obligations at issue relate to the sale of electricity for resale in the California ISO's and PX's interstate spot markets. The Commission's authority, under FPA Section 201(b), encompasses "the sale of electric energy at wholesale in interstate commerce." In the restructured California market, all sales into the PX or ISO meet this definition. *See also* FPA § 201(b)(2) (defining wholesale sales). The wholesale sales of electricity here thus fall within the subject matter of the Commission's statutory authority.

The question at issue involves the interplay between that subject matter jurisdiction and the express limitations on FPA jurisdiction to public utilities. The Commission's authority under FPA Section 206(a) is limited to rates "collected by any public utility for any . . . sale subject to the jurisdiction of the Commission." FPA Section 201(d)(2)(f) provides that, except where specifically stated otherwise, no provision of Part II of the FPA applies to "the United States, a state or any political subdivision of a state, or any agency, authority or instrumentality of any one or more of the foregoing").

b. *FERC Has Jurisdiction Over the Subject Matter of the Sales at Issue*

At issue is whether the Commission can assert jurisdiction over the California ISO and PX wholesale electricity markets in a manner that encompasses non-public utility sellers that are not subject to our direct jurisdiction under FPA Section 206. Under the specific circumstances presented, we conclude that such jurisdiction may properly be asserted over non-public utility sellers of energy. Under the single price auction mechanism that operated in the centralized ISO and PX spot markets, all sellers agreed to accept the same clearing price for any given sale. From the time the Commission acted on SDG&E's complaint, all sellers into those markets were on notice that those clearing prices, and the market rules that set the clearing prices, were subject to change if they were found to be unjust and unreasonable. For example, the November 1 Order states: ". . . if the Commission finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices . . . we may require refunds for sales made during the refund effective period."[54]

Our action here establishes a revised method for calculating the just and reasonable clearing prices to be applied in those markets for the period beginning October 2, 2000. This is pursuant to the Commission's authority under FPA Section 206 to fix the just and reasonable rate. Our action thus revises the market clearing prices that all market participants previously agreed to accept for their sales. In this context, we see no reason to treat non-public utility

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[54] 93 FERC at p. 61,370; *see also* December 15 Order, 94 FERC at pp. 62,010-11 (same).

sellers differently, as they are receiving the same price, the just and reasonable market clearing price established pursuant to market rules approved by this Commission, that they expected to obtain for their wholesale sales into the centralized ISO and PX spot markets.

When faced with a similar question under the Natural Gas Act, the D.C. Circuit concluded that the Commission could exert rate authority over non-jurisdictional entities to fulfill its statutory responsibilities regarding the subject matter of its NGA jurisdiction. *In United Gas Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), local distribution companies and municipalities, both of whom are exempt from NGA jurisdiction, challenged application of FERC's Open Access Rules to their release of their own capacity on a pipeline system. The court focused on the subject matter of the transaction, not the parties involved, to determine the Commission's authority to act. The court found that, notwithstanding the LDCs' exemption from the NGA, "the Commission's jurisdiction attaches to the subject of the capacity release transaction: interstate transportation rights." 88 F.3d at 1152. Further, the court found that exempting LDCs would allow them to engage in capacity release "without regard to the principles of open access and nondiscrimination that are at the heart" of the program. *Id.* That result would be "directly contrary to Congress' intent in enacting the [NGA]." *Id.* Consequently, the court found the Commission properly included LDCs within the regulatory plan to further the statutory goals.

Similarly, here, Commission jurisdiction attaches to the subject matter of the affected transactions: wholesale sales of electric energy in interstate

commerce through a Commission-authorized and Commission-regulated centralized clearinghouse that set a market clearing price for all wholesale seller participants, including non-public utilities. Exempting transactions involving non-public utility sellers from refund scrutiny here would allow them to make such sales without regard to the just and reasonable standard that applies to the market clearing price administered by the ISO (and previously by the PX), and that pervades all Commission ratemaking policies.

It is noteworthy that California may not regulate out of state sellers and has declined to regulate California non-public utilities' sales in the California centralized ISO and PX spot markets. As a result, absent FERC jurisdiction, a regulatory gap for these sales could exist. Such a result could preclude us from protecting consumers from exploitation in these markets, one of our statutory objectives under the FPA.

For essentially the same reasons, the court in *UDC* found the Commission could require compliance with its capacity release regulations from municipalities.

> FERC may, consistent with the NGA, require municipalities to comply with its capacity release regulations . . . . FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate gas *pipelines*. The pipelines' role in capacity release is absolutely central, and the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers.

88 F.3d at 1154 (emphasis in original; footnotes omitted). The court also found "compelling" that prior to

adoption of the Commission's capacity release program, neither jurisdictional nor non-jurisdictional entities could release capacity. Thus, as the Commission set up the program that benefitted both jurisdictional and non-jurisdictional parties, it could establish rules by which *all* parties must abide. *Id.*

Here, the central transactions, wholesale sales of energy in interstate commerce, were governed by FERC-approved rules and a FERC-jurisdictional ISO and PX. Those transactions thus fell within FERC's jurisdiction regardless of the jurisdictional nature of the sellers or buyers. Further, the centralized wholesale spot electricity markets operated by the California ISO and PX were established (and have been modified) subject to FERC review and approval. Because the market did not exist prior to FERC authorization, all those who participated in the market had to recognize the controlling weight of FERC authority. Moreover, it is fair that all those who benefitted from this market also bear responsibility for remedying any potential unlawful transactions that might have occurred in the market.

Non-public utility sellers in the California market entered into various arrangements that acknowledged the Commission's authority over the centralized transactions. For example, in *Pacific Gas and Electric Co., et al.*, 82 FERC ¶ 61,326 (1998), many non-public utility sellers accepted a FERC-authorized, *pro-forma* Scheduling Coordinator Agreement. *Id.* at p. 62,283.[55] Among the obligations under the Agreement, parties agreed "to comply with the terms and

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[55] One such seller was City of Los Angeles, Department of Water & Power, whose Agreement was docketed as ER98-1934-000. *Id.*

conditions of the ISO Tariff and ISO Protocols." *Id.* For the PX, the Commission required that parties sign a FERC-authorized, *pro-forma* Participation Agreement. *California Power Exchange Corp.*, 83 FERC ¶ 61,186 (1998). Against opposition, the Commission concluded that the Participation Agreement and "the services provided under the PX Tariff are jurisdictional." *Id.* at p. 61,771. The Commission indicated that the Agreement "is the contract under which the California PX provides these services to its customers" and, as such, could be required to be filed in accordance with FPA Section 205(c). *Id.* A large number of non-public utility sellers executed the Participation Agreement. *See, e.g.*, PX letter filing of January 25, 2001 (index of parties who executed the Agreement as of December 31, 2000).

Placing jurisdictional and non-jurisdictional sellers on the same footing for refund purposes promotes the underlying goals of the FPA. Under California's restructuring system, interstate, wholesale sales of electric energy were transacted largely through hourly single price auctions, which meant that all bidders into these spot markets received the same price for a specific sale. In fact, prior to Commission modification, California public utilities were required by California to transact exclusively through the PX under the mandatory buy/sell rule.

Consequently, if the price for a specific sale is found to be unjust and unreasonable, then all sellers who obtained that price received an unjust and unreasonable rate. To the extent the Commission determines refunds are an appropriate remedy for that sale, consumers can only be made whole by refunds

from all sellers who received the excessive price.[56] As non-public utility sellers of energy and ancillary services accounted for up to 30 percent of all sales in the California centralized ISO and PX spot markets, excluding them from a potential refund remedy could have a serious detrimental effect on consumers.

3. *Refund Liability Can Apply from October 2, 2000 Through June 20, 2001*

The above discussion also largely disposes of any claim that the Commission is impermissibly applying refund liability to non-public utility sellers back to the October 2, 2000, refund effective date that we previously announced. Because refund obligations relate to factual issues concerning past periods, their resolution is considered to be adjudication. Adjudications are generally given retroactive effect. *See Harper v. Virginia Dept. of Taxation*, 509 U.S. 86, 94-95 (1993) (referring to "the fundamental rule of retrospective operation that has governed judicial decisions for near a thousand years"). The Court has declined to accept equitable reliance as grounds for limiting the retroactive application of an adjudicatory decision. "The federal law applicable to a particular case does not turn on whether litigants actually relied on an old rule [or] how they would suffer from retroactive application of a new one." *Id.* at n.9 (citation and quotation marks omitted).

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[56] We note that non-public utilities (*e.g.*, Turlock Irrigation District and the City of Burbank) are seeking refunds for what they perceive are excessive charges paid in these markets. Under the maxim that those who seek equity must do equity, *McQuiddy v. Ware*, 87 U.S. 14, 19 (1873); *In re Gardenshire*, 209 F.3d 1145, 1152 n.11 (9th Cir. 2000), it would only be fair that these same utilities be willing to pay refunds related to any excessive amounts they may have collected.

Of course, in the instant matter, as explained above, the non-public utility sellers were well aware that these transactions involved wholesale sales of electricity subject to FERC jurisdiction. These sellers had executed the *pro forma* agreements established by the Commission that indicated, in part, their willingness to comply with the terms of the FERC-jurisdictional ISO or PX tariffs. These factors undermine possible claims that non-public utility sellers of energy could reasonably have relied on their sales for resale of electricity into the centralized interstate California ISO and PX spot markets not properly being subject to FERC jurisdiction.

The Supreme Court's discussion of retroactivity arose in the context of judicial adjudication, but the same principles counsel strongly for like treatment in agency adjudications. *See Southwestern Public Service Co. v. FERC*, 952 F.2d 555, 563 (D.C. Cir. 1992) (indicating FERC "should take note" of recent Supreme Court case that "may forbid agencies to apply rules with selective retrospectivity.") (citation omitted). The D.C. Circuit also recently indicated that selective retroactivity[57] for remedial purposes "breaches the principle that litigants in similar situations should be treated the same, a fundamental component of *stare decisis* and the rule of law generally." *Nat'l Fuel Gas Supply Corp. v. FERC*, 59 F.3d 1781, 1789 (D.C. Cir. 1995) (citation omitted). Here, as discussed above, public utility and non-public utility sellers under the single price auction system used in the affected markets were similarly situated regarding the price they received for their sales for resale of

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[57] That is, prospective application for some, and retrospective application for others.

electricity, and thus should be treated similarly in the consideration of whether refunds should be required.

The D.C. Circuit has, however, expressly declined to require that agency adjudications enforcing agency decisions apply retroactively. *See, e.g., Power Corp. of America*, 245 F.3d at 847. Instead, the court applies a five-part test for deciding if retroactivity is inappropriate. *Williams Natural Gas Co. v. FERC*, 3 F.3d 1544, 1553-55 (D.C. Cir. 1993); *see Retail Wholesale & Dept. Store Union v. NLRB*, 466 F.2d 380, 390 (D.C. Cir. 1972) (one formulation of criteria). Under these criteria, our determination that non-public utility sellers of energy in the California market can be liable for refunds should apply retroactively.

The initial criterion asks whether the issue is one of first impression. We have no trouble finding that the instant question is, given that California was the first state to restructure its electricity market and the Commission had never dealt with market-wide refunds in a single price auction for widespread centralized spot purchases of wholesale electricity in interstate commerce. The next criterion looks to whether Commission action seeks to fill a void in an unsettled area of the law. For the same reasons mentioned in the first criterion, this factor weighs in favor of retroactivity. The Commission seeks to redress a previously unencountered situation in a manner that furthers the underlying purpose of the FPA.

The third criterion asks the extent to which parties relied on the old rule. Here, there was no old rule to apply to the precise situation. But, in any event, non-public utility sellers should have recognized their sales for resale into the centralized ISO or PX

spot markets were the subject of FERC jurisdiction and scrutiny. Among other things, FERC's investigation into the ISO and PX market practices and rules, with indications in the August 23 Order that possible remedies included changes to the market clearing price mechanisms and refunds, should have alerted non-public utility (as well as public utility) sellers of FERC's authority over their sales in those markets. Moreover, those sellers signed FERC *pro forma* agreements that indicated their willingness to comply with FERC-authorized tariffs.

The fourth and fifth criteria also weigh in favor of retroactivity. Ordering non-public utility sellers to refund amounts received in excess of just and reasonable rates does not impose an unfair burden, but merely place those sellers in the same position as public utility sellers. Finally, the statutory interest in protecting consumers against exploitation is furthered by subjecting non-public utility sellers, who represent up to 30 percent of all sales into the California ISO and PX spot markets during the applicable time period, to possible refund liability to the same extent as public utility sellers. Otherwise, consumers will not be made whole for any prices found to be excessive. Moreover, fundamental fairness dictates that in the context of a single price auction, where all bidders received the same price for a specific sale, all those parties should now bear the responsibility of refunding any amounts found to be unjust and unreasonable.

In short, the balance tips decidedly in favor of retroactive application of refund liability to October 2, 2000, for all sellers in the California ISO and PX spot markets.

4. *DWR Transactions*

By motion dated March 1, 2001, the Oversight Board requested clarification and extension of the December 15 Order, arguing that DWR bilateral contracts should be subject to refund. These contracts became an issue when, on January 17, 2001, the Governor of California issued an emergency proclamation giving DWR authority to enter into arrangements to purchase power. DWR began purchasing under this authority the next day. DWR has purchased substantial amounts of energy in the ISO's Imbalance Energy market and is in the process of executing long-term purchases. The California Commission and SoCal Edison supported the motion. Numerous other parties opposed the motion, contending that the relief sought would be inconsistent with the objectives of the December 15 Order and because the proposed changes to parties' market-based rate authorizations would have to be considered under FPA Section 206.

Subsequently, a number of parties filed comments on the Chief Judge's Report arguing that the DWR bilateral contracts should remain outside the scope of the Commission's refund orders given that these transactions represent bargained-for exchanges between willing buyers and sellers (with DWR picking and choosing the transactions it wanted, exercising discretion and exhibiting price response).[58]

We believe imposing after-the-fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding when the Com-

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[58] *See* Statement of the Undersigned Generators to the Chief Judge, dated July 9, 2001, at 8.

mission consistently encouraged California load serving entities to acquire a balanced portfolio of short, medium and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000, through June 20, 2001 to include transactions outside the ISO and PX centralized markets would simply hinder the ability of parties to enter into new bilateral contracts. Accordingly, the Commission will deny the Oversight Board's motion.[59]

Further, we note that while DWR is a market participant that competes with other suppliers and purchasers of energy and ancillary services in the ISO markets, unlike other market participants, DWR has had access to the ISO's control room and associated written materials, visual observations, and oral statements regarding the ISO's markets, systems, operations and activities.[60] This has provided DWR a competitive advantage in entering into its bilateral contracts. In addition, by voluntarily entering into bilateral transactions outside the ISO and PX, DWR made a conscious decision to forego the refund protection that the Commission provided for purchases through the ISO and PX. Thus, there is no equitable rationale that supports making DWR's bilateral contracts subject to refund.

The Commission will issue a further order concerning the standards of conduct between the ISO and DWR in Docket No. ER01-889.

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[59] If DWR (or any other party) believes any of its contracts are unjust and unreasonable, it may file a complaint under FPA Section 206 to seek modification of such contracts.

[60] *See* Confidentiality, Non-Disclosure and Use of Information Agreement dated January 24, 2001 filed as Attachment G by the ISO on June 19, 2001 in Docket No. ER01-889-005.

5. *OOM Transactions*

Several parties request clarification that the ISO's out-of-market (OOM) purchases are subject to refund. We grant this clarification. As we stated previously in our November 1 Order, "the electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed and [] these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain conditions."[61] The order noted that the "California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA."[62] These statements are most true with respect to the ISO's daily OOM purchases for obtaining the resources it needs to reliably operate the grid.

As stated in the August 23 Order, if there is insufficient supply in the ISO markets, then the ISO must procure additional supplies at the last minute with OOM purchases in order to meet its needs for the operating day. Historically, the ISO procured on a daily basis only the resources needed for the operating day. Not only did this procurement practice put pressure on the grid operator to secure needed resources at the last minute, but the practice was uneconomical. Because the ISO is the supplier of last resort for these services, when OOM calls are made, suppliers realize that the ISO is in a must-buy situation. For this reason, we directed the ISO to imme-

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[61] 93 FERC at p. 61,349.

[62] *Id.* at p. 61,350.

diately institute a more forward approach to procuring the resources necessary to reliably operate the grid.[63]

To the extent the ISO made spot market OOM purchases (*i.e.*, 24 hours or less and that were entered into the day of or day prior to delivery), such purchases are no different than purchases through its markets. Both types of purchases are made by the ISO in order to procure the resources necessary to reliably operate the grid. Therefore, we clarify that spot market OOM transactions are subject to refund and subject to the hourly mitigated price established in the ordered hearing. The hourly price will establish the maximum price with refunds for transactions over this level.

6. *Sales Made Pursuant to DOE Orders*

PPL Montana, PPL EnergyPlus, and PPL Southwest Generation Holdings (PPL Parties) state that in the exercise of his authority under Section 202(c) of the FPA, the Secretary of Energy (Secretary), in a series of orders directed PPL Montana, among others, to make the necessary arrangements to supply energy as requested by the California ISO. PPL Parties maintain that such sales made pursuant to the orders issued by the Secretary under this authority should not be subject to refund because they were not made pursuant to Section 205 of the FPA. The ISO maintains that sales made pursuant to Section 202(c) should be subject to refund.

PPL Parties state that Section 202(c) has its own mechanism for determining sales prices. Under the section, sales are to be made at an agreed upon price. Only if price and terms cannot be agreed to in accor-

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[63] 92 FERC at p. 61,608.

dance with the existing regulations, the terms are to be immediately prescribed by the Secretary and the price referred to this Commission for subsequent determination of a rate it determines is "just and reasonable."[64] According to PPL Parties, there is nothing in Section 202(c) that authorizes the payment of refunds or the redetermination of sales prices where there has been mutual agreement.

Furthermore, PPL Parties state that the Secretary specifically directed in his orders that "the terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order are to be agreed to by the parties." Therefore, they assert that any action by the Commission to alter the terms of agreements voluntarily reached by ordering refunds would be inconsistent with the Secretary's mandate.

We agree that rates for transactions entered into under Section 202(c) in compliance with the Secretary's orders are outside the scope of this proceeding. The Secretary has not referred any sales to this Commission for a rate determination; if any had been referred here, they would have been reviewed in a separate proceeding.

7. *PG&E Bankruptcy*

We note that on April 6, 2001, PG&E filed for Chapter 11 bankruptcy protection. Although the Bankruptcy Code provides that the filing of a bankruptcy petition automatically stays certain actions against the debtor,[65] the Code also provides an exception from this automatic stay for:

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[64] 10 C.F.R. § 205.376 (2001).

[65] 11 U.S.C. § 362(a)(1) (1994 & Supp. 2000).

> An action or proceeding by a governmental unit . . . to enforce such governmental unit's or organization's police and regulatory power, including the enforcement of a judgment other than a money judgment, obtained in an action or proceeding by the governmental unit to enforce such governmental unit's or organization's police or regulatory power.[66]

The Commission has found in the past that actions taken under the authority granted it by the Federal Power Act and the controlling regulations fit within this exception, and, therefore, are exempt from the automatic stay provision.[67] In the instant matter, we are exercising our regulatory power under Section 206 of the Federal Power Act as permitted by Section 362(b)(4) of the Bankruptcy Code to issue an order that does not threaten the bankruptcy court's control over the property of the bankruptcy estate. As this order establishes the formula for refunds but does

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[66] 11 U.S.C. § 362(b)(4) (1994 & Supp. 2000).

[67] *See Virginia Electric and Power Company*, 84 FERC ¶ 61,254 (1998); and *Century Power Corp.*, 56 FERC ¶ 61,087 (1991). The Commission conclusion on this matter is consistent with judicial precedent regarding the scope of the exemption to the automatic stay. *E.g.*, *Board of Governors of the Federal Reserve System v. MCorp Fin., Inc.*, 502 U.S. 32 (1991); *SEC v. Brennan*, 250 F.3d 65 (2nd Cir. 2000); *NLRB v. Continental Hagen Corp.*, 932 F.2d 828 (9th Cir. 1991); *United States v. Commonwealth Cos. Inc.*, 913 F.2d 518 (8th Cir. 1990); *NLRB v. Edward Cooper Painting, Inc.*, 804 F.2d 934 (6th Cir. 1986); *Penn Terra Ltd. v. Dept. of Environmental Resources*, 733 F.2d 267 (3rd Cir. 1984); *In re Pacific Gas and Electric Co., et al.*, No. 01-30932 (Bankr. N.D.Cal. June 1, 2001) (finding the regulatory exception applies to a California Commission decision affecting PG&E's financial condition); *see generally* 3 Collier on Bankruptcy § 362.05 (15th ed. rev. 2000).

not impose any monetary obligation on PG&E, it has no effect on PG&E's bankruptcy estate.

C. *Refund Calculation Methodology*

We will adopt the recommendations of the Chief Judge, as modified below, and apply the methodology set out in the June 19 Order from the October 2, 2000, refund effective date, through June 20, 2001 to determine the amount of refunds due to the customers in the ISO and PX spot markets. As the Chief Judge recognized, the methodology in the June 19 Order must be modified in order to be applied to the period October 2, 2000, through June 20, 2001. In this respect, we will direct the ISO to make the modifications discussed below to the methodology presented in the June 19 Order, for the purposes of developing a factual record for analyzing these markets during the refund period.

The scope of the June 19 price mitigation extends to all spot market hours. Applying this to the period October 2, 2000, through June 20, 2001, will enlarge the number of hours that the March 9 Refund Order made subject to refund for the period January 1 through May 28, 2001. Accordingly, we will grant the requests for rehearing of the March 9 Refund Order that seek to increase the hours of price mitigation for this period. In addition, we note that the June 19 Order mitigates prices during all hours effective as of June 21, 2001. This leaves a gap from May 29 through June 20, 2001, when price mitigation only applied to periods of system emergencies. In order to maintain a consistent approach during all periods of time, the Commission will require application of the refund calculation methodology discussed below to non-reserve deficiency hours from May 29 through June 20, 2001. Transactions that occurred

during reserve deficiency hours in this period, already mitigated as a result of the April 26 Order, will not be affected.

The June 19 Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet the load in the ISO's real-time market. The June 19 Order also established a "must offer" requirement that each generator offer all available and uncommitted capacity in real-time. The ISO, County of Los Angeles, California Commission, SDG&E, SoCal Edison, and the Oversight Board (collectively, California Parties) argue that in applying the June 19 Order for the period October 2, 2000 through June 20, 2001, the methodology must include a simulation of the must offer requirement (an assumed economic dispatch). This modification to the actual data lowers the heat rate for establishing the market clearing price because it assumes that all generation that was not dispatched was really available, and that more imports were available than the actual quantities. The California Parties allege that the use of historical dispatch would yield higher prices than the prices resulting from using an assumed economic dispatch, and higher prices would reward the exercise of market power.

We did not institute the must offer requirement or the marginal bidding requirement until May 28, 2001, and it is unreasonable to re-create the markets to apply such requirements for the period October 2, 2000 through June 20, 2001. Generators actually dispatched in the markets during these periods have specific marginal costs that are reasonably recovered under our methodology. The end result of using an assumed economic dispatch (prices lower than the actual marginal costs of the last generator dis-

patched) unfairly punishes the very generators that helped keep the lights on in California. Therefore, we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time the maximum heat rate of any unit dispatched each hour in the real-time imbalance market for the period October 2, 2000 through May 28, 2001.[68] This should address the concerns of numerous commenters that application of the June 19 methodology from October 2, 2000 forward, particularly with respect to marketers that are price takers, would be confiscatory.

The June 19 Order also established a mitigated price for hours of non-reserve deficiency at 85 percent of the market clearing price established during the last Stage 1 reserve deficiency. The Chief Judge ruled that, on a retroactive basis, the 85 percent maximum price for non-reserve deficiency periods could distort re-creation of a competitive market. Most commenters, including California Parties, Southern California Water Company and Dynegy, agree that the methodology for calculating refunds should not incorporate this element and instead should calculate a competitive price for every hour of the period in question. California Parties argue that including the 85 percent formula in calculating refunds would provide sellers with an unjustified off-

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[68] For the periods when the ISO instituted 10-minute dispatch protocols, we direct the ISO to take the average of the maximum heat rates for the six 10-minute periods in order to develop a market clearing price for application in the hourly auctions (including the PX markets). For the purposes of re-running the settlement/billing process in the imbalance market, we direct the ISO to substitute the revised market clearing prices calculated for each 10-minute period in its settlement software.

peak premium. Due to the support for this modification and because no party has raised a legitimate concern over the Chief Judge's rationale, we will adopt his recommendation.

In support of the recommendation to use the daily spot market price for gas, the Chief Judge relied on record evidence that the energy sales at issue were made with spot gas purchases. PG&E maintains that there is no need to alter the treatment of gas costs in the June 19 Order (*i.e.*, averaging the bid-point of the monthly bid-week prices reported by Gas Daily for three spot market prices reported for California). Moreover, PG&E contends that the use of spot gas prices is unreasonable as there have been large differentials between such prices and average costs.

We note that PG&E has not refuted the underlying record evidence relied upon by the Chief Judge in making his recommendation to use daily spot purchases (*i.e.*, that such sales were typically made with gas purchased in the spot market).[69] In addition, we note that spot purchases have traditionally been used to calculate the replacement cost of fuel. Given that the gas treatment in the June 19 Order was intended to address and influence purchasing decisions for prospective sales, there is simply no support for requiring a similar treatment for retroactive application to past sales.

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[69] Prior to market-based rates, economy sales (or sales from capacity available after a public utility's requirements and other firm customers were served) were the equivalent of spot market sales. Economy sales were priced at incremental or marginal cost, which was based on a fuel charge equal to the replacement cost of fuel. *See, e.g., Indiana & Michigan Electric Company, et al.*, 10 FERC ¶ 61,295 (1980).

Mirant argues that the use of the Malin delivery point for an input for northern California suppliers is inappropriate because this index price is less than the PG&E City Gate price. According to Mirant, using an average of the two indexes will not reflect the actual fuel cost to the generators in northern California. If sellers in California, such as Mirant, do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering all of their generating units in the WSCC for the duration of the mitigation period and including the refund period.

A number of Marketers and public utilities outside of California state that their purchased power costs, which may be higher than the hourly price calculated under the methodology adopted by the Commission, should be used to offset any potential refunds. Consistent with our prospective ruling in the June 19 Order, we will not allow such a showing for the period October 2, 2000 through June 20, 2001. We note that the public utilities outside of California typically entered into must-take purchase power contracts for weekly, monthly or longer periods. Their short-term purchases were made in order to either meet minimum reserve requirements or to supply their native load. To the extent these public utilities' total resources, both owned and purchased, temporarily exceeded their actual total system load, the surplus was available as opportunity sales in the spot markets including the ISO and PX spot markets. Because the purchased power costs of these utilities were sunk costs similar to their investment in their own plant, any revenues generated from off-system sales at market based rates reduces their initial purchase power costs to serve their native load. Even

the lower mitigated hourly prices determined in the hearing will subsidize these public utilities' overall cost of providing native load service. Finally, as noted in the June 19 Order, under the FPA and our authorization for market-based rates, sellers are not guaranteed to recover all costs, but are provided the opportunity to do so.

Several sellers support the use of separate gas prices for northern and southern California. The California Parties object to any change in the gas prices used in the June 19 Order, stating that it is unclear how two gas prices could be used under the June 19th methodology. Reliant adds that the methodology should maintain a single price auction mechanism for determining refunds instead of separate northern and southern market clearing prices. We find the approach suggested by the Chief Judge to be a workable addition to the June 19 Order methodology consistent with the determination of the actual running costs of the marginal unit. We will adopt the method proposed by the Chief Judge and direct the ISO to apply the appropriate gas price once the marginal unit is determined. If that marginal unit is located in the North of Path 15 (NP15) zone, then the ISO should calculate the market clearing price by using the average daily spot gas price for PG&E Citygate and Malin. If that marginal unit is located in the South of Path 15 (SP15) zone, the ISO should calculate the market clearing price by using the average daily spot gas price for Southern California Gas large packages. We clarify that these inputs are to be used to calculate a single clearing price.

While we are adopting the Chief Judge's recommendation to use daily spot gas prices and the three delivery points as reported by Financial Times

Energy's "Gas Daily," we will adopt one modification based on comments filed by Intelligence Press, Inc. (Intelligence Press). Intelligence Press states that the Commission has in the past used a composite of published market prices and notes that using multiple sources addresses a number of concerns including reducing the effect of errors that might occur in gathering and reporting the spot price data. We believe that these are valid points. Accordingly, the gas inputs recommended by the Chief Judge should be based on the simple average daily spot price as reported by Gas Daily, NGI's Daily Gas Price index and Inside FERC's Gas Market Report. The last published gas prices should be used in calculating the refund price for the days that these publications are not published (weekends and holidays).[70]

The June 19 Order also established an O&M adder of $6/MWh to be included in the calculated market clearing price. The Chief Judge recommended the same adder be included in the methodology for calculating refunds. No parties commented on this adder and we therefore adopt its use in the methodology.

The Chief Judge recommended that the methodology establish a separate expense category for demonstrable emissions costs that sellers may subtract from their respective refund calculations, consistent with the mitigation methodology established in the June 19 Order. Reliant maintains that NOX costs and other environmental mitigation fees represent

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[70] We note that NGI's Daily Gas Price index and Inside FERC's Gas Market Report did not have a listing for Southern California Gas Large Packages during the refund period. Therefore, we instruct the ISO to use the Financial Times Energy's "Gas Daily" for calculation of the southern gas price during the refund period.

costs that a generator actually incurred in producing energy and, as such, should be included in the calculation of cost for the marginal unit. Although we note that the inclusion of emissions costs in the calculation of the costs for the marginal unit is sound economic theory, we find that in practice, actual emissions costs vary by location, time period, and duration. We find that the incorporation of such costs, which have not been demonstrated to be hourly costs, in the context of calculating hourly marginal costs for the purposes of establishing refund liability, would present an insurmountable burden. We find that allowing full recovery by the generators of all of their demonstrable emissions costs incurred during the refund period is appropriate. Because the emissions cost will not be included in the revised market clearing price, we direct all sellers to submit during the hearing their emissions costs incurred during the refund period for subtraction from their respective refund liabilities.

California Parties object to the inclusion of a ten percent creditworthiness adder, stating that sellers' actions in charging high prices forced SoCal Edison and PG&E to lose their credit rating, and that a credit adder would reward them for these actions. Sellers support the creditworthiness adder although they state that ten percent could be insufficient to accurately reflect the credit risk associated with making sales into California during the refund period. PPL Montana states that sellers making the sales for which refunds are contemplated not only were deterred from obtaining appropriate credit guarantees, but have experienced actual harm in the form of non-payment.

We find that the inclusion of a creditworthiness adder in the methodology to determine refund liability is appropriate and necessary. One result of parties' failure to reach settlement in this proceeding is that payment of overdue amounts has not been assured. The methodology we set forth will determine the just and reasonable rates that buyers will pay, but it cannot provide assurances that buyers, one of which is currently embroiled in bankruptcy proceedings, will pay the full amounts due. Therefore, we will adopt the recommendation of the Chief Judge that the 10 percent adder should be included in the market clearing price. At this time we will limit the adder to all transactions that occurred after the downgrade of SoCal Edison and PG&E's bond ratings on January 5, 2001.

Once the ISO has calculated the hourly market clearing prices for the refund period, this data should be used by both the ISO and PX to rerun their settlement/billing processes and all penalties. These revised settlements should be submitted to the administrative law judge and parties should use this information to form the basis of any offsets (*i.e.*, the amounts to be refunded against the payments past due). We direct the administrative law judge to certify this information, in its entirety, to the Commission.

California Parties support the calculation of interest against refunds and maintain that Commission precedent requires an interest calculation. Sellers believe that if interest charges are assessed that they should be assessed symmetrically to refunded amounts and to amounts past due. We will direct the calculation of interest on both refunds and receivables past due, pursuant to the methodology for the calculation

of interest under Section 35.19a of the Code of Federal Regulations.

D. *Evidentiary Hearing Proceeding*

The Chief Judge's Report stated that the differences between what the purchasers and the sellers in the California market believe are owed in refunds raise material issues of fact and recommended an evidentiary hearing be ordered in this proceeding. Several parties commented that there were no issues of material fact because there had been no offer of settlement requiring litigation, and urged the Commission to continue the settlement process.[71] Others commented that the Commission has sufficient record evidence to support a refund remedy and believed there is no need for a hearing to determine the methodology.[72] Still others supported the Chief Judge's conclusion but recommended various methods to limit the scope of further proceedings.[73]

The Commission agrees that, despite the voluminous record accumulated in this proceeding to date, material issues of fact remain that prevent the Commission from ordering refunds at this time. We believe that the most orderly and expeditious method of determining what refunds are owed will be to convene an evidentiary hearing before an administrative law judge. Accordingly, the Commission will establish an evidentiary hearing to further develop the factual record so that the refund methodology presented in this order may be implemented, to be convened by Administrative Law Judge Birchman.

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[71] *See, e.g.*, comments of Pinnacle West Companies, Public Service Company of New Mexico.

[72] *See, e.g.*, comments of PG&E, California Parties.

[73] Comments of Reliant, Mirant.

The scope of the hearing will be limited to the collection of data needed to apply the refund methodology prescribed herein; we will direct Judge Birchman not to entertain any arguments relating to the methodology or the scope of transactions subject to refunds, except as otherwise indicated in this order.

In order to develop the factual record, the ISO will be directed to provide Judge Birchman with a re-creation of the mitigated prices that result from using the methodology described herein for every hour from October 2, 2000 through June 20, 2001, within fifteen days of the date this order is issued. The ISO and PX are further directed to rerun their settlement/billing process as described above and provide this data to Judge Birchman.

We will direct Judge Birchman to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established herein; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California. We will require the judge to certify findings of fact to the Commission, without an initial decision, by no later than 45 days after the date that the ISO provides this data.

E. *Pacific Northwest Proceeding*

The Chief Judge noted that there was little time to address the issues raised by the Pacific Northwest Parties. Moreover, these parties did not have data on what they claim they were owed, nor on an amount of refunds due them. The Chief Judge requested comments on the necessity of convening subsequent settlement conferences to address the issues. Comments jointly filed by Pacific Northwest

Net Purchasers state that there was inadequate time either to document the harm suffered, or to engage in meaningful settlement discussions with affected sellers. Given these circumstances, they request additional process on this matter.

Spot market sales outside of California were not based on bids into an auction, and instead were made through bilateral contracts.[74] Many commenters note the enormity of attempting to unravel such transactions retroactively. Still others claim that this task must be undertaken in order to put other parties on an equal footing with California. In light of the complexities associated with these retroactive bilateral calculations and the absence of any further development of this issue in the settlement proceeding, and in recognition that the prior settlement proceeding focused primarily on California, we will establish a separate preliminary evidentiary proceeding pertaining to the Northwest. The proceeding is intended to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001.[75] The record should establish the volume of the transactions, the identification of

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[74] What is a "spot market" sale for bilateral transactions in the Pacific Northwest may differ from what is a "spot market" sale in the California ISO and PX organized spot markets.

[75] December 25, 2000 is the earliest refund effective date the Commission could establish for Puget's complaint regarding rates in the Pacific Northwest if the Commission determines that it is appropriate to deny Puget Sound's motion to withdraw the complaint, and, further, to grant rehearing of the Commission's previous determination not to set the complaint for hearing.

the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. This will help the Commission to determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest. We also strongly encourage the parties to try to settle past accounts.

Accordingly, we direct all parties to the Puget Sound complaint proceeding to participate in the proceeding and to focus on settling past accounts related to spot market sales in the Pacific Northwest. Interested parties to the SDG&E proceeding may participate at their discretion. We direct the Chief Administrative Law Judge or his designee to appoint a judge to convene a conference no later than August 2, 2001, and we require the parties to provide the data described above to the presiding judge no later than 15 days thereafter. We direct the presiding judge to complete discussions within 30 days following the submission of this data. The judge shall make a recommendation and certify the record and findings of fact to the Commission within 7 days after the close of the discussions.[76]

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly Sections 205 and 206 thereof, and pursuant to the Commission's Rules of

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[76] The Commission intends to take up the Motion to Withdraw in Docket No. EL01-10-000, *Puget Sound Energy Inc. v. All Jurisdictional Sellers of Energy, et al.*, in an expeditious time frame after the judge's certification of the record.

Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket Nos. EL00-95-031 and EL00-98-030 concerning refund amounts, as discussed in the body of this order.

(B) Administrative Law Judge Birchman shall convene a conference in this proceeding, to be held as soon as practicable after the date of this order, in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

(C) The ISO is hereby directed to provide Judge Birchman with data, as discussed in the body of this order. Judge Birchman is hereby directed to certify the record and findings of fact to the Commission no later than 45 days after such data is provided.

(D) The parties to the proceeding in Docket No. EL01-10-000 are hereby directed to participate in discussions before an administrative law judge, to be designated by the Chief Administrative Law Judge, as discussed in the body of this order.

(E) No later than 7 days after the completion of discussions in Docket No. EL01-10-000, the designated judge shall make a recommendation to the Commission.

(F) Requests for rehearing of the November 1 Order regarding the Commission's retroactive refund authority (*i.e.*, refund authority prior to October 2, 2000) are hereby denied.

(G) Requests for rehearing of the March 9 Refund Order regarding the Commission's authority to require refunds from non-public utilities and regarding the application of price mitigation during all hours are hereby granted.

(H) The Oversight Board's March 1 motion is hereby denied.

(I) The request for rehearing of the December 15 Order filed by Southern California Water Company is hereby dismissed.

(J) The request for rehearing of the March 9 Order filed by American Public Power Association is hereby dismissed.

Commissioner Massey dissented in part and concurred in part with a separate statement attached.

Commissioners Breathitt and Massey jointly dissented in part with a separate statement attached.

Commissioner Breathitt dissented in part with a separate statement attached.

William L. MASSEY, Commissioner, *dissenting in part and concurring in part:*

I am pleased that the Commission today addresses head on the tough issue of refunds for the victims that took the brunt of the wildly dysfunctional Western power market. The issue comes back to us after a brief attempt by our Chief ALJ to bring the parties together in a voluntary settlement. Judge Wagner did an admirable job under very difficult circumstances and we owe him our gratitude for the valiant effort. But now it is time for the Commission to fulfill its responsibility to the customers of California and other parts of the West.

One of the issues where I disagree with the majority is extending a potential refund obligation to non-public utilities that are otherwise not jurisdictional. Commissioner Breathitt and I are issuing a joint dissent on that issue today.

Today's order also provides very specific guidance on how refunds are to be calculated back to October 2, 2000. In essence, the order applies retrospectively the mitigation measures the Commission set out in our June 19th mitigation order with some adjustments recommended by Judge Wagner in his excellent report on the settlement negotiations. Although I agree with many of the conclusions we reach, I disagree with some aspects of that guidance.

My first area of disagreement is the use of daily spot gas prices as reported in various publications to determine the fuel cost component of the mitigated market clearing prices. It simply is not clear to me that generators purchased gas at those spot prices to replace the gas used to generate electricity for sale into the spot markets. And we do not have to guess at whether they did or not. We are dealing with an historical locked in period for which expenses are known or knowable. During that period, we can use actual fuel costs to determine the just and reasonable price, and we should do so. In supporting the majority's decision to use a different gas index for the refund calculation than that used for the prospective mitigation, the order says that "the gas treatment in the June 19 order was intended to address and influence purchasing decision for prospective sales" and that "there is simply no support for requiring a similar treatment for retroactive application to past sales." I agree with that. We are not trying to influence future behavior in this order, but instead are deter-

mining just and reasonable prices for past periods and refunds for customers. We should use the most accurate data we have, and that is actual fuel costs. Therefore, I will dissent from this aspect of the order.

I also object to the inclusion of a 10% creditworthiness adder in determining the mitigated market clearing price that will be used to calculate refunds. I expressed concerns with including this adder as part of the Commission's forward looking price mitigation plan established in the June 19 order. Today, I conclude that this adder is unnecessary in calculating refunds. Prices skyrocketed in June 2000 and remained high for the better part of a year. Indeed, the Commission found that conditions in the market "have caused, and continue to have the potential to cause, unjust and unreasonable rates . . . under certain conditions."[1] Yet today's order concludes that there is no opportunity for refunds for transactions before October 2, 2000. I support that conclusion but it is clear that sellers charged prices that were not just and reasonable before that date. The fact that there will be no refunds for sales before October 2, 2000 presents strong equity considerations influencing my conclusion that the creditworthiness adder is not necessary in this generous market. Therefore, I will dissent from this aspect of the order.

As a final note on the California portion of this order, I am concerned that the Commission still fails to address squarely the issue of generation withholding during the refund period and before. The market clearing prices for the refund period are determined by a method that uses the dispatch that actually

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[1] *San Diego Gas & Electric Company, et al.*, 93 FERC ¶ 61,121, at pp. 61,349 50 (2000), *reh'g pending*.

occurred. As some parties suggest here, the actual dispatches reflect the withholding of more efficient units that drove up the market clearing price. The record in this case contains a number of studies that indicate withholding. Two that come to mind are those submitted by the ISO's director of market analysis, Dr. Anjali Sheffrin, and by Drs. Paul Joskow and Ed Kahn. I find these studies instructive. Today's order fails to take the issue of withholding into account in setting a refund formula.

A separate concern is what could the Commission do if we found deliberate withholding in the California spot markets, or anywhere else for that matter. In a section of the order dealing with whether we can go back before the October 2, 2000 date for refund liability, the order says we can do so only if the seller "did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs." My concern is that the Commission would not be able either to find that these conditions were violated or take other actions against sellers that deliberately withheld power from the market because, until April 26, 2001, there were no tariff conditions prohibiting withholding in western markets. This is a major flaw in Commission policy. The Commission must set the rules of the road in our tariffs. As the Commission updates its standards for approving market based rates, we must include generic tariff conditions nationwide that prohibit this kind of bad behavior. I urge my colleagues to consider prompt action to remedy this flaw.

I have one final comment on today's order. The order establishes a 15-day proceeding to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for

sales in the Pacific Northwest for the period beginning December 25, 2000. This proceeding has its genesis in the complaint of Puget Sound Energy. Buyers in the Northwest paid outrageous prices for power that caused much economic dislocation. To that end, I am pleased that we finally take up the issue of bringing refund relief to that region. The order states correctly that spot market sales in the Pacific Northwest may differ from the definition of a spot market sale in the California organized spot market. I agree. I believe spot sale in the Pacific Northwest could include sales up to a month's duration or even longer. I would be prepared formally to grant rehearing and investigate the Puget complaint today, but it seems that today's order charts an evidentiary path to reach this conclusion ultimately, and I concur with these provisions.

For these reasons, I dissent in part from, and concur in part with, today's order.

Linda K. BREATHITT and William L. MASSEY, Commissioners, *dissenting in part:*

We respectfully disagree with the conclusion reached in this order to extend a potential refund obligation to sellers into the California spot markets that are not jurisdictional public utilities. The majority concludes that while "we do not have direct regulatory authority over power sales by non-public utilities, we do have authority to order them to abide by the market rules we establish to make refunds of unjust and unreasonable rates for sales pursuant to those market rules."

Although this rationale certainly has strong appeal, especially as a matter of equity, we are not sufficiently comfortable with it. The refund rules of

Section 206 of the Federal Power Act are rather specific. If Congress had wanted the Commission to have refund authority over non-public utilities, Congress would have surely so specified. The breath-taking conclusion that this agency has the power to tell non-public utilities to pay money back will come as a shock to most observers.

We understand and appreciate the strong equity rationale behind the majority's decision. Perhaps this interpretation of the Commission's refund authority ought to be the law, but we are not yet persuaded that it is allowed by existing law. Unfortunately, the majority's conclusion ensures that the matter of refunds will probably never be settled and will be litigated for years.

For these reasons, we dissent in part from today's order.

Linda K. BREATHITT, Commissioner, *dissenting in part:*

I respectfully disagree with the majority's inclusion of a ten percent creditworthiness adder in the methodology to determine refund liability. The rationale stated in this order, that sellers cannot be assured that buyers will pay the full refunds due, is not persuasive in my opinion.

I was concerned about the creditworthiness adder included on a prospective basis through the market clearing price methodology established in our June 19, 2001 order. There I concurred on this issue. Today I will dissent on this issue because I see even less reason for such an adder to be included on a retroactive basis through the refund methodology.

FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc., Complainant v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Respondents, Docket Nos. EL01-10-000 and EL01-10-001

Recommendations and Proposed Findings of Fact

(Issued September 24, 2001)

Carmen A. Cintron, Presiding Administrative Law Judge.

To the Commission:

I. Background

By order issued July 25, 2001, the Commission ordered a preliminary evidentiary hearing:

> to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. The record should establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. This record would help the Commission determine "the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest.

See San Diego Gas & Electric Company, 96 FERC ¶ 61,120, at p. 61,520 (2001) ("*San Diego Gas*") ("July 25 Order").

The Commission instructed that a prehearing conference be held before August 2, 2001, and parties were to provide the data described above to the presiding judge no later than 15 days after the prehearing conference. Thirty days thereafter, the hearing was to conclude. The Commission ordered that the presiding judge make a recommendation and certify the record and findings of fact seven days later.

A. *Preliminary Evidentiary Hearing*

On August 1, 2001 a prehearing conference was held, where a procedural schedule was adopted. An order issued on August 3rd, clarified that all sellers in the Pacific Northwest were to submit the data required by the Commission in the July 25 Order. On August 8, 2001 an order was issued approving groups for the marshaling of the evidence and the hearing. To wit, five groups were created. The Net Purchasers Group ("NPG"), the California parties aligned with this group; the Transaction Finality Group ("TFG"); the Federal Power Marketing Group; the State Entities Group and All others. An order establishing the format for the August 16 data submissions was issued on August 9, 2001, modified on August 13 and August 16. These data submissions were requested pursuant to the July 25 Order's language that the record "should establish the volume of transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts." *San Diego Gas*, *supra* slip op. at 43. In accordance with the July 25 Order, data submissions were filed on August 16, 2001. Oral argument

was held on August 20, 2001 where a number of matters were addressed.

B. *Discovery*

Discovery responses were limited to three business days, served by e-mail with voluminous submissions served on Staff by CD-Rom or diskette. Depositions were not allowed. Discovery responses were subsequently limited to four days and discovery closed on August 30, 2001.

C. *August 16 Data Submissions*

The August 16 data submissions were not distributed to all parties but served solely on the presiding ALJ and Staff.

D. *Issues*

By order issued August 23, 2001, the following issues were adopted in this proceeding:[1]

1. What were "spot market bilateral sales" in the Pacific Northwest as defined in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14), during the period beginning December 25, 2000 through June 20, 2001?

2. May unjust and unreasonable prices have been charged for spot market bilateral sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

a. What was the volume of spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

b. What were the price and terms and conditions of the sales contracts for spot market bilateral sales

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[1] It bears noting that the parties could not agree on a joint stipulation of issues and filed at least two proposals with various comments.

transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

c. Who were the net sellers and net buyers of electric energy in spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

d. What is the appropriate methodology for determining a just and reasonable rate for transactions that occurred in the bilateral spot market in the Pacific Northwest during the relevant period?

e. Did sellers of electric energy in spot market bilateral sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 charge unjust and unreasonable prices?

f. Did any such seller exercise market power, or violate any conditions or limitations of its market based tariffs or agreements entered into under the Western Systems Power Pool Agreement?

3. Are refunds lawful or appropriate for spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 and what is the extent of any potential refunds?

E. *Ripple Claims*

Ripple claims have been defined as sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund. By order issued August 28, 2001 (Order on Ripple Claims) it was determined that ripple claims are essential to determining the existence, and the extent, of refund liability for spot market purchases in the PNW. However, ripple claims were not entertained in this proceeding, because they are contingent on a

finding that refunds are due, and because there is no time to develop a record on these claims. Moreover, potential ripple claimants were allowed to submit offers of proof regarding their claims. In this order, it was determined that all parties reserved their rights, without qualification, to raise ripple refund claims in response to any future determination that such parties are liable for refunds.

F. *The Hearing*

The hearing lasted three days, with cross-examination waived for numerous witnesses. The TFG filed a motion alleging due process violations because of the abbreviated hearing schedule mandated by the Commission. (TFG Renewed Due Process Objections to the Commission's Abbreviated Briefing And Hearing Schedule filed September 4, 2001).[2]

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[2] Potlatch Corporation ("Potlatch") filed a motion to intervene on September 4, 2001, replies were due on September 6, 2001. It stands unopposed and therefore for good cause, it is now granted. Potlatch must accept the record that was developed prior to its late intervention. On September 14, 2001 the City of Burbank, California filed a Motion to Permit Interlocutory Appeal of three separate rulings made in this case of three requests by this party. To wit, Order on Motion To Certify Question; Motion To Strike testimony of witnesses and motion for summary Judgment. The motion to Permit Interlocutory Appeal is denied. City of Burbank failed to show extraordinary circumstances warranting the relief it seeks. *See* Rule 715, 18 C.F.R. § 385.715. On September 19, 2001, the record was reopened for the limited purpose of accepting for filing data submissions from Pacific Northwest Generating Cooperative ("PNGC") and a letter from Reliant Energy Services, Inc. to clarify that its sales to Idaho Power during year 2000 were not made within the refund period of this case or were not made for delivery in or through the Pacific Northwest.

G. *Briefs/Proposed Findings*

Post hearing briefs were filed on September 17, 2001, by the following: Net Purchasers Group; California Parties; Transaction Finality Group;[3] Bonneville Power Administration; Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission ("Washington Oregon utilities"); Attorney General of Washington; Puget Sound Energy, Inc.; PPL Montana, LLC and PPL EnergyPlus, LLC; Clark Public Utilities; Williams Energy Marketing and Trading; Atofina Chemicals, Inc., Columbia Falls Aluminum Company and Golden Northwest Aluminum, Inc.; Alcoa Inc.; Public Service Company of New Mexico; The City of Redding, California; Grant County, Benton County, Franklin County and Grays Harbor County PUDS; Eugene Water & Electric Board; Sierra Pacific Power Company and Nevada Power Company; Sacramento Municipal District; Enron Power Marketing, Inc. & Enron Energy Services, Inc.; TransAlta Energy Marketing (U.S.), Inc.; IDACORP Energy, LP; POWEREX Corp; Washington PUDs; Duke Energy Trading and Marketing L.L.C.; Public Service Company of Colorado; Modesto Irrigation District; Non Jurisdictional Municipal Systems; Kaiser Aluminum & Chemical Corporation; Wah Chang and Staff.

Additionally, the following parties submitted findings without briefs: El Paso Merchant Energy, L.P.; Pinnacle West Companies; PacifiCorp; McMinnville Water & Light Commission; Morgan Stanley Group, Inc.; City of Burbank, Salt River Project Agricultural

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[3] The parties comprising these groups are listed in Order Approving Groups, issued August 8, 2001.

Improvement and Power District submitted a letter joining in the brief of the non-jurisdictional municipal entities.

II. RECOMMENDATIONS

For ease of reading the following format is followed in this document: First, the issues are stated. The parties' contentions follow. Finally, my recommendations are described.

A. *Procedural Issues in the Commission's July 25 Order*

On July 24, 2001, Puget Sound filed a Motion to Strike. In this motion, Puget Sound sought to strike the following on the grounds that they were not parties to the proceeding, The City of Seattle's Motion to Intervene Out of Time and Opposition to Puget Sound's Motion to Dismiss; Attorney General of Washington Motion to Intervene and Statement of Opposition to Motion of Puget Sound to Withdraw Its Complaint; Answer of City of Tacoma and Port of Seattle to Motion to Dismiss. Puget Sound also filed an Answer in Opposition to the Motions for Leave to Intervene Out of Time Filed by the City of Seattle and the Attorney General of Washington. On July 26, 2001, City of Tacoma and Port of Seattle filed Motions for Leave to Intervene Out of Time.

The July 25 Order did not address the opposition filed by Puget Sound (City of Seattle and Attorney General of Washington). However, the Commission granted as unopposed the following: Oregon PUC, Washington Commission, City of Seattle, Attorney General of Washington. The interventions of City of Seattle and Attorney General of Washington were opposed.

Puget Sound's motion to strike was not addressed in the July 25 Order. It appears that City of Tacoma and Port of Seattle's answer to Puget Sound's motion to dismiss its complaint preceded their intervention requests.

The July 25 Order did not address Tacoma's and Port of Seattle's motions to intervene.

Recommendation: The oppositions to interventions filed by Puget Sound (City of Seattle and Attorney General of Washington), interventions by Tacoma and Port of Seattle and Puget Sound's Motion to Strike should be addressed by the Commission.

B. *Issues*

1. What were "spot market bilateral sales" in the Pacific Northwest as defined in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14), during the period beginning December 25, 2000 through June 20, 2001?

The Attorney General of Washington argues that the definition of spot markets is not the real issue, but that refunds should be ordered for all transactions that were influenced, and made unreasonably costly by the high price of the market transactions in the California market.

NPG

Net Purchasers Group ("NPG") asserts that the Pacific Northwest spot market bilateral sales for which refunds should be provided in this proceeding include the following:

(1) All hourly, daily, weekly, balance of the month, monthly, quarterly and longer purchase transactions of up to one year, for delivery anytime up to

one year from the date of the transaction, entered into during the refund period; and

(2) All purchases made during the refund period under contracts and service schedules of any duration at prices tied to Pacific Northwest daily price indices.

According to NPG, in the July 25 Order, the Commission recognized that "spot market" sales for bilateral transactions in the Pacific Northwest may differ from "spot market" sales in the California ISO and PX spot markets.[4] Commissioner Massey stated: "I believe spot sale[s] in the Pacific Northwest could include sales up to a month's duration or even longer."[5] The record demonstrates that a sensible and fair result is to recognize that, in the Pacific Northwest, "spot market bilateral sales" include transactions entered into during the refund period on a bilateral basis for terms ranging from next-hour, next day, balance of month, monthly, and quarterly through a term of twelve months.

Defining "spot market bilateral sales" in a technical way based upon textbook definitions, power markets in other regions of the country, or an opinion poll that identifies only a subset of typical Pacific Northwest spot market sales transactions only creates arbitrary and inequitable distinctions among parties, depending upon the nature of the transactions they entered into. Likewise, in order to reach an equitable result for Pacific Northwest consumers, the Commission should also order refunds for all purchases made during the refund period under con-

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[4] July 25 Order, 96 FERC at p. 61,520 n.74.

[5] *Id.* at pp. 61,522-23 (Massey, Commissioner, dissenting in part and concurring in part).

tracts and service schedules of any duration at prices tied to Pacific Northwest daily price indices. NPG argues that there is broad agreement among Commission staff and the load-serving utilities in the Pacific Northwest, whether or not they are seeking refunds in this proceeding, that spot market sales encompass transactions of up to a year citing the testimony of McCullough, Movish, Spettel, Watters and Tingle-Stewart discussed below.

Robert F. McCullough testified on behalf of Seattle City Light that "[t]he Pacific Northwest treats all purchases and sales of less than one year duration as spot purchases."[6] Philip J. Movish testified on behalf of the City of Tacoma ("Tacoma"), the Port of Seattle (the "Port") and Northern Wasco County People's Utility District ("Northern Wasco") that "all hourly, daily, bi-weekly, balance of month, and longer term purchase transactions that are . . . affected by changes in the market clearing price should be considered in the determination of unjust and unreasonable charges."[7] Scott C. Spettel, employed by the Eugene Water and Electric Board ("EWEB") since 1982 in positions relating to power scheduling, management, and planning, testified that he "regard[s] wholesale power bought and sold for terms ranging from next-hour, next-day, balance of month, monthly, and quarterly through a term of twelve months as being 'spot market' transactions or contracts."[8]

Stan Watters, Vice President of Trading and Originations for PacifiCorp, testified that "PacifiCorp believes that it would be more appropriate to define

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[6] Exh. NPG-1 at 11, lines 2-3.

[7] Exh. NPG-45 at 17-18; Exh. NPG-33 at 18.

[8] Initial Testimony of Scott C. Spettel, Exh. NPG-74 at 7.

the spot market, for purposes of these proceedings, to include all transactions of up to and including one month in duration."[9] Mr. Watters explains that PacifiCorp enters into spot transactions of "up to one month in duration that allow [PacifiCorp] to triangulate toward a precise balance of loads and resources."[10] Mr. Watters concludes that:

> We [PacifiCorp] know of no principled basis for distinguishing transactions up to one month in duration that we make from the one-hour purchase or sale that we make on a particular day of the month. Both transactions are integral to the load balancing function of load-serving entities and both are substantially affected by whatever imperfections might have existed in near-term markets.[11]

Commission staff witness Natalie Tingle-Stewart testified that the Pacific Northwest spot markets are not constrained to day-ahead sales. Based on the "terms and conditions" of the transactions identified to Commission Staff by, and the testimony of, many parties in this proceeding, "spot market transactions in the Pacific Northwest should be transactions which are for an hourly, daily, monthly basis and can be up to one year. . . . [T]his appears to be the acceptable business practice of pricing transactions for the entities located within the Pacific Northwest Region."[12]

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[9] Rebuttal Testimony of Stan Watters, Exh. PacifiCorp-1 at 2.

[10] *Id.*

[11] *Id.*

[12] Prepared Direct Testimony of Natalie Y. Tingle-Stewart, Exh. S-1 at 17; FERC Transcript at 1241, lines 10-13.

The Transaction Finality Group ("TFG"), according to NPG, seeks to define the Pacific Northwest spot market as "any transaction with a *duration* of 24 hours or less that is *prescheduled* no more than 24 hours in advance of delivery, with an allowance for the conventions of scheduling for weekends and holidays."[13] By their own admission, this definition is not based on information relating to the Pacific Northwest spot market or the "standardized products" sold in that market. Rather, TFG's experts based this definition on "our experience in *other* markets, our experience in *other* regions and so on and so forth that gives a fairly objective definition of what the spot market is."[14] Of course, their "fairly objective" definition rests solely on the TFG's interpretations of generic information drawn from sources unrelated to the Pacific Northwest spot market. For this reason, the "spot market" definition offered by the TFG should be rejected, NPG avers.

For example, NPG argues, the MIT Dictionary of Economics is far too generalized to have any bearing on technical questions specifically relating to the Pacific Northwest.[15] Likewise, the TFG's excerpts from the Chicago Board of Trade's Commodity Training Manual relate to a different geographic region and actually apply only to "cash commodities" such as "actual physical commodit[ies] someone is buying or selling, *e.g.*, soybeans, corn, gold, silver, Treasury bonds, etc." The Bloomberg definition of "spot price" also relates only to a "commodity," which is defined as "food, metal, or another fixed physical substance."

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[13] Exh. AE-1, at 14 (emphasis added).

[14] Van Vactor, FERC Transcript at 1116 (emphasis added).

[15] *See* ENR Ex.-28.

None of these definitions relates to the analysis of spot market sales in the Pacific Northwest at issue in this proceeding. According to NPG, TFG's heavy reliance on these unrelated definitions, however, underscores its failure to address the unique features *i.e.*, the realities, of the Pacific Northwest spot market.

The TFG, NPG argues, attempts to rationalize its artificial limitation of "preschedul[ing]" within 24 hours of delivery requirement by focusing on the concept of "immediate delivery."[16] The TFG extracts this concept from definitions found in such sources as the MIT Dictionary of Economics, the Chicago Board of Trade's Commodity Training Manual, and the Bloomberg website.[17] *None* of these sources, however, defines the term "immediate delivery" as delivery within any specific period of time (such as 24 hours). Recognizing this defect in their claim, the TFG merely offers that "[t]he physical mechanisms for delivery of commodities shape the structure of the relevant spot market, according to NPG."[18]

NPG further argues that nothing in the definitions the TFG cites states that spot market sales must result in product deliveries that have a duration of no more than 24 hours. Transactions for "immediate delivery" may extend in duration well beyond the artificial 24-hour limitation espoused by the TFG. For example, balance-of-the-month electricity transactions are a prevalent form of trading in the Pacific Northwest, as the TFG admits.[19] The TFG further

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[16] *See* Exh. ENR-25, at 4-5.

[17] *See* Exhs. ENR-26, ENR-27, ENR-28, ENR-29.

[18] Exh. ENR-25, at 2.

[19] *See* Exh. ENR-25, at 6.

admits, as it must, that these transactions "us[e] much the same process as described for the bilateral day-ahead market (except for the fact that the period being traded is the remainder of the month)."[20] Given the realities of the relevant market, argues NPG, and even reading the generic definitions on their face, the undefined term "immediate delivery" clearly does not support the TFG's 24-hour *durational* restriction on "spot market" sales in the Pacific Northwest.

To compensate for the scant experience of its "experts" in the Pacific Northwest power market,[21] the TFG claims that its "spot market" definition takes into account relevant market practices simply because one of its experts conducted four telephone interviews and an "informal survey" of Pacific Northwest traders.[22] According to NPG, TFG admits, however, that both the telephone interviews and "informal survey" *were all with employees of TFG members*,[23] at least five of whom were actually witnesses for TFG members.[24] Moreover, of the 26 survey respondents, only two or three represented load serving utilities.[25]

NPG argues that Pacific Northwest spot market sales encompass monthly, quarterly and yearly transactions because all involve "standardized product[s]" traded on the spot at transparent and fluctuating

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[20] Exh. AE-1, at 13.

[21] *See* Transcript at 1125-27.

[22] *See* Exh. ENR-10, at 9; Exh. ENR-25, at 3.

[23] *See* FERC Transcript at 1144-45.

[24] *See id.* at 1145-48.

[25] *See id.* at 1148-49.

prices. As Tim Culbertson, who testified on behalf of Public Utility District No. 2 of Grant County and three other PUDs, explains:

> I believe the definition ought to focus on how standard the product is, how liquid the product is, and how transparent the price is .... I believe that "spot market" should be defined on a longer basis than the real-time and day-ahead transactions due to the fact that monthly, quarterly, and even transactions up to a year involve a standardized product, can be consummated just fast as a day-ahead or real-time deal, and trade at prices that are, for the most part, transparent.[26]

It is appropriate to define the Pacific Northwest spot market in terms of standard products because all standard products are bought and sold on the "spot" at prices that are transparent, NPG maintains. Standard products are typically traded during a brief direct telephone call either involving a broker or person-to-person contact.[27] Such transactions are generally not the product of lengthy negotiations as in the case, for example, of a 20-year power sales agreement. The process by which such standard product transactions are conducted is basically the same for hourly, daily, monthly, quarterly, and yearly transactions, according to NPG.

NPG asserts that the nature of the Pacific Northwest spot market reflects the scheduling difficulties imposed by widespread reliance on hydroelectric resources. The "Northwest Power Pool generation

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[26] Prepared Answering Testimony of Tim Culbertson, Exh. GT-1 at 6.

[27] *See, e.g.*, Stelzer, Exh. AE-1 at 13, lines 1-11.

mix is dominated by hydroelectric generation."[28] "[P]rimarily hydroelectric systems operate very differently from thermal systems like those in California."[29] Hydroelectric resources "are fuel limited, not capacity limited .... The operating problem that faces Pacific Northwest generators is that the hydroelectric projects do not have enough water to meet all of the loads – even though they might well have sufficient capacity to meet peak loads without any need for any other resources."[30]

Because hydroelectric projects "are not capable of running all of the time," Pacific Northwest load serving utilities must make spot purchases "on an hourly, daily, weekly or monthly basis to 'refill' reservoirs."[31] The fact that the Pacific Northwest relies primarily on hydroelectric resources forces load serving utilities to purchase standard products for periods of a day, week, month, quarter and year that are traded on the spot, NPG argues. As Mr. McCullough testi-

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[28] Prepared Direct Testimony of Robert F. McCullough, Exh. NPG-1 at 6. *See also* Prepared Responsive Testimony of Christopher Stelzer, AE-1 at 3 ("over 60% of the Pacific Northwest's energy supply will come from hydroelectric facilities in a typical year, and the percentage has been even higher in the past"); Prepared Direct Testimony of Natalie Y. Tingle-Stewart, S-1 at 8 ("hydro power supplies approximately 60 to 70 percent of the electricity in the Northwest"); Prepared Direct Testimony of Dolores Stegeman, NPG Exh. 27 at page 3, lines 76-77.

[29] Prepared Direct Testimony of Robert F. McCullough, Exh. NPG-1 at 5.

[30] *Id.*

[31] *Id. See also* Rebuttal Testimony of Stan Watters, PacifiCorp-1 at 3 ("as we [PacifiCorp] get closer to the month of delivery, we begin a process of buying and selling power in transactions of up to one month in duration that allows us to triangulate toward a precise balance of loads and resources.").

fied, the Pacific Northwest spot market is related to "the Pacific Northwest Coordination Agreement which controls how the major [hydroelectric] projects are dispatched. This Agreement envisages that all purchases and thermal dispatch will be block loaded to stretch the available supply of hydroelectricity."[32]

Pacific Northwest load serving utilities, which rely primarily on hydroelectric resources, should not be punished for prudently purchasing power on weekly, monthly, quarterly or yearly bases, NPG avers. These utilities made purchases of these durations in order to balance their expected load and resource needs and requirements.[33] This practice comports with the Commission's stated objective that load serving utilities should not overly rely on the more volatile next-hour and next-day purchases.[34] It also is consistent with good public policy, NPG maintains.

The bilateral transactions for which refunds should be permitted should also include all sales during the refund period under contracts or service schedules of any duration tied to Pacific Northwest daily price indices, according to NPG. NPG avers that those

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[32] McCullough, Exh. NPG-1, at 11.

[33] *See, e.g.*, Rebuttal Testimony of Stan Watters, Exh. PacifiCorp-1 at 3. (PacifiCorp enters into transactions of "up to one month in duration" to achieve "a precise balance of loads and resources"); Green Exh. NPG-4 at 10, lines 225-27 ("SCL's trading activities are limited to purchasing power to meet native customer loads . . . and selling energy during times of surplus"). Direct Testimony of Dolores Stegeman, Exh. NPG-27 at 829, lines 185-196 ("These resources provide a low-cost stable base for Tacoma Power's portfolio.").

[34] *See, e.g.*, June 19 Order, 95 FERC at p. 62,546 ("reduction of the size of the ISO's spot market . . . was, and remains, the cornerstone of our price mitigation").

price indices were affected by the distorted market clearing prices in the California PX and ISO spot markets.[35] These transactions would include, for example, all purchases under contracts pursuant to which prices are "market indexed and based on the Dow Jones Mid-Columbia Electricity Price Index."[36] The dysfunction in the California PX and ISO spot markets negatively impacted daily price indices in the Pacific Northwest.[37] Therefore, NPG argues, the prices at which power was bought and sold in the Pacific Northwest during the refund period under contracts and service schedules tied to Pacific Northwest daily price indices were rendered unjust and unreasonable, regardless of whether the underlying transaction is entered into pursuant to a short- or long-term contract.[38]

Furthermore, NPG avers, refunds for these transactions comport with the Commission's responsibility to protect all purchasers from not only unjust and unreasonable rates, but also discriminatory treatment.

According to NPG, two primary competing proposals of what constitutes the "Pacific Northwest" have emerged in this proceeding: 1) the geographic area encompassed by the Northwest Power Pool ("NWPP"); and 2) the drainage basin of the Columbia River and

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[35] *See* Prepared Direct Testimony of Philip J. Movish on Behalf of the City of Tacoma and Port of Seattle, Exh. NPG-33 at 17; Prepared Direct Testimony of Philip J. Movish on Behalf of Northern Wasco, Exh. NPG-45 at 16 (same); Puget Complaint at 8 (noting "a high degree of correlation between" the index of California electricity prices and the Dow Jones Mid-Columbia Electricity Price Index).

[36] Exh. NPG-45, at 17.

[37] *See* Exh. NPG-33, at 17.

[38] *See* Movish Rebuttal Testimony, Exh. NPG-60 at 3.

its tributaries as defined in the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (the "PNEPPCA"), 16 U.S.C. §§ 839a(14). The first proposal defines an appropriate geographic area; the second is inapplicable to this proceeding.

The geographic scope of the NWPP "is an area th[at] includes the utilities that are active in trading electricity within the Pacific Northwest."[39] "It is logical to use the marketing area for the Pacific Northwest [for the purpose of determining the extent of potential refunds in this proceeding], not an arbitrary geographic division of that area."[40] Moreover, NPG avers, the area encompassed by the NWPP "is a definition of very long standing," because the NWPP has been in operation since 1957, and the Pacific Northwest Coordination Agreement, which governs the relationship among Northwest utilities, was signed in 1962.[41]

On the other hand, NPG maintains, the geographic area defined in the PNEPPCA is inappropriate. The PNEPPCA definition encompasses an area significantly smaller than the NWPP, and its boundaries would cut through service areas such as PacifiCorp's.[42] This definition "has more to do with the environmental issues in the [PNEPPCA] than anything to do with [the WSCC [Western Systems Coordinat-

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[39] Prepared Direct Testimony of Robert F. McCullough, NPG-1 at 2-3.

[40] *Id.*

[41] *Id.* *See also* Prepared Answering Testimony of Tim Culbertson, GT-1 at 7-8 (agreeing that definition of "Pacific Northwest" should be based on the Pacific Northwest Coordination Agreement).

[42] *See* NPG-1 at 3-4.

ing Council] market.]"[43] As all of the area encompassed by the NWPP is included in the WSCC, and the Commission has ordered prospective price mitigation for the WSCC, it is appropriate to use the NWPP area.

The PNEPPCA definition encompasses a narrow geographic band (75 miles) around the Columbia River and its tributaries, intended to include "the anadromous fisheries that have been severely threatened by the hydroelectric projects along the Columbia River. This simply has nothing to do with the WSCC market."[44] The Commission should use a geographic area relevant to electric power marketing, *i.e.*, the area covered by the NWPP, not an irrelevant geographic area related to fish and wildlife management concerns.

California Parties

California Parties argue along similar lines as the NPG. According to the California Parties, all experts agreed that the "spot market" in the PNW was not limited to real-time or near real-time transactions, but included some forward transactions and can extend to longer-term transactions influenced by daily index prices. (Movish, NPG-33 at 12-15; Saleba, GSS-1 at 7:4-11; Wolak, CAL-5 at 6:19-9:7; Mason, NPG-62, at 6:25-7:6; Watters, PacifiCorp-1 at 4-5). The only point of disagreement concerns which forward transactions to include. Short-term forward power transactions are designed to "fill in" the avail-

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[43] Rebuttal Testimony of Robert F. McCullough, NPG-68 at 7.

[44] *Id.*, *see* 16 U.S.C. § 839(6) (1994) (one of several purposes of the PNEPPCA is "to protect, mitigate and enhance the fish and wildlife . . . of the Columbia River and its tributaries, particularly anadromous fish").

ability of hydroelectric projects to meet load. (McCullough, NPG-1 at 6:19-7:1). These "fill in" transactions form the spot market and these transactions can vary in form and duration. For instance:

- Seattle City Light [seeking refunds] defines the spot market as including transactions up to one year based on conventions established in the PNW Coordination Agreement. (McCullough, NPG-1 at 11:2-3.)

- Eugene Water and Electric Board [seeking refunds] regards transactions ranging from next-hour, next day, balance of month, monthly, quarterly and even a term of twelve months to be spot. (Spettel, NPG-74 at 7.)

- City of Tacoma, Port of Seattle and Northern Wasco County Peoples Utility District [seeking refunds] asserted that all hourly, daily, bi-weekly, balance of the month, and longer term purchase transactions indexed at prices that may change on a daily or hourly basis are "spot transactions." (Movish, NPG-33 at 17-18 and Movish Rebuttal, NPG-60 at 18.)

- Public Utility District No. 2 of Grant County [not seeking refunds] states that spot transactions encompass monthly, quarterly, and even transactions up to a year because all involve standardized products traded at transparent and fluctuating prices. (Culbertson, GT-1 at 6-7.)

- Bonneville Power Administration ("BPA") [not seeking refunds], the entity that according to the Transaction Finality Group ("TFG") dominates the marketing of power in the Northwest (Van Vactor, ENR-1 at 1:22-11:2), classifies spot transactions as

including all sales within a month and balance of the month. (Oliver Direct, BPA-1 at 5).

- PacifiCorp [not seeking refunds] advanced that it would be proper to define the spot market to include all transactions of up to, and including, one month in duration. (Watters, PacifiCorp-1 at p.2.)[45]

- FERC Staff concluded that spot market transactions in the PNW should consist of transactions which are for an hourly, daily, monthly basis and can be up to one year. (Tingle-Stewart, S-1 at 17.)

Like the NPG, California Parties contend that in the physical commodities markets, upon which the TFG heavily relies,[46] a spot transaction may "initiate" immediate delivery, but it rarely, if ever results in immediate receipt by the purchaser. Equally significant, the immediate delivery in the physical commodities market has no relation to the rate of consumption by the purchaser. Electricity cannot be stored. Therefore, a purchaser of spot

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[45] Mr. Watters on behalf of PacifiCorp concluded that there is "no principled basis for distinguishing transactions up to one month in duration that we make from the one-hour purchase or sale that we make on a particular day or month. Both transactions are integral to the load balancing function of load-serving entities and both are substantially affected by whatever imperfections might have existed in the near term-markets." (PacifiCorp-1 at 4-5.)

[46] The TFG, for example, cites to the excerpts from the Chicago Board of Trade's Commodity Training Manual and Bloomberg. The Chicago Board of Trade refers to "cash commodities" such as "actual physical commodity[ies] someone is buying or selling, *e.g.*, soybeans, corn, gold, silver, treasury bonds, etc." Similarly, the Bloomberg cite refers to a commodity which is defined as "food, metal, or another fixed physical substance."

electricity cannot accept it all at once and ration it over the time period in which it is needed. Thus, the TFG's definition necessarily rests on a concept of immediacy that is irrelevant to the electricity market.

Moreover, as noted by BPA, "[w]ithin the month and balance of the month transactions can be very-short-term in nature (days), and are usually made because of unanticipated changes in load or generation, after the month begins." (Oliver, BPA-1 at 6.) Thus, while the 24-hour time frame may conform to scheduling conventions, and there will be a need for real-time balancing of resources, these facts should not and do not comport with the reality of short-term purchasing decisions in the PNW. If schedulers know that an energy requirement exists, they will normally choose to make one purchase rather than multiple daily transactions, California Parties maintain. (McCullough Rebuttal, NPG-68 at 16.)

Rather than constrain the definition of "spot market" to a narrow range of transactions, the Commission recognized that the definition of spot market must serve "to determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest."[47] Dr. Frank Wolak, witness for the California Parties, explains that market power can influence short-term power purchases because it takes approximately two years for a new entrant to deliver new supply; sellers of electricity for delivery of energy within this two-year time frame can exercise market power and drive prices above the prices that would prevail in a workably competitive market. (CAL-5 at 3:10-6:15.) Because the Commission has the responsibility under

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[47] July 25 Order, 96 FERC at p. 61,520.

the FPA to ensure that electricity is sold at just and reasonable rates, the definition of "spot market" for purposes of this proceeding should include all transactions that could have been tainted by the exercise of market power, the California Parties state.

The August 23, 2001, *Order on Issues* adopted the definition of the PNW set forth in the Pacific Northwest Electric Power Planning and Conservation Act ("Conservation Act").[48] For the California Parties, the issue is not how to geographically define the PNW. Rather, the question is what constitutes a sale in the PNW. Industry custom, fundamental notions of justice, as well as prior orders in this proceeding and prior Commission orders, dictate that transactions encompassed by this proceeding should properly include all purchases and sales of electric energy that originate, are delivered to, or are transmitted in the area defined by the Conservation Act or in the broader WSPP area as advocated by NPG.

Refunds for sales to CERS in the PNW are appropriately pursued in this proceeding. Under the July 25 Order, CERS' bilateral contracts in the PNW are eligible for refunds, just as are those of every other purchaser of power in the PNW. While suppliers may argue that this proceeding is intended to address only the claims of entities *physically located* in the PNW, the Commission and orders in this proceeding have previously ruled to the contrary. Regardless of whether the wholesale purchaser or retail end-user resides in California or the PNW, if the power in question was purchased in the PNW under a bilateral contract, it is within the scope of this proceeding. The July 25 Order affirms that, to the extent CERS

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[48] *(See also)* July 25 Order, 96 FERC at p. 61,502 fn. 19.

was a party to transactions in the PNW, those transactions are eligible for refunds, the California Parties argue.

The refund claim of the California Parties in this proceeding consists of the subset of CERS transactions made at or through certain interconnections with control areas in the PNW. (Tr. at 886:23-888:1 and 921:13-16.)[49] BPA – a party adverse to the California Parties in this proceeding – acknowledges that the border delivery points known as the California Oregon Border ("COB") and the Nevada Oregon Border ("NOB") are "in the PNW" within the meaning of the statute. (Oliver Direct, BPA-1 at 5). Similarly, according to the California Parties, the TFG admits that the Conservation Act definition "includes all of the region's important electricity trading hubs for the [PNW]; those hubs are the California Oregon boarder ("COB"), Mid Columbia ("Mid-C"), and the Northern Rockies." (Van Vactor, ENR-1 at 5:17-19; Adamson, ENR-10 at 7:2.)

Furthermore, the California Parties argue, each transaction underlying the California Parties' refund claim was entered into pursuant to the Western Systems Power Pool ("WSPP") Agreement. (Tr. at 864:12-14 and 889:8-12.)[50] Section 33.2 of the WSPP Agreement provides, in pertinent part, that "[t]itle to and risk of loss of the electric energy shall pass from the Seller to the Purchaser at the delivery point

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[49] *(See also)* Affidavit of William Green filed on August 23, 2001 as Attachment 1 to the Answer of the California Parties to the Motion of the Transaction Finality Group to Strike Testimony of the California Parties.

[50] The exceptions are exchange agreements outlined in CAL-3.

agreed to in the Confirmation Agreement."[51] Thus, it is an essential indicium of completion of the wholesale transaction, i.e., the transfer of title of the electrical energy, occurred within the PNW.

In furtherance of its argument, the California Parties contend, that nothing in the July 25 Order suggests that refunds for PNW bilateral transactions will be considered for all parties *except* CERS. The July 25 Order excludes CERS' and all other bilateral transactions from the *San Diego* refund proceeding, ruling that that proceeding is confined to transactions through the ISO and CalPX markets.[52] It does not preclude consideration of refunds for *all* bilateral transactions entered into by any California party in *any* market. The Commission did not limit in any manner the identity of purchasers who may be eligible for refunds in the PNW.

While the California Parties have requested rehearing of the Commission's erroneous decision to exclude CERS' transactions from refund consideration in the *San Diego* docket, CERS' bilateral transactions in the PNW are *not* purchases through the California ISO or PX markets. Consequently, refund claims in this proceeding as to such transactions do not duplicate claims currently set for evidentiary hearing in the *San Diego* case.[53] Rather, to the extent that CERS had bilateral purchases in the PNW,

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[51] The WSPP Purchase Agreement is S-6, introduced by Staff Witness Poffenberger.

[52] 96 FERC at p. 61,515.

[53] As Mr. Green testified, *all* of the California Parties' claims for transactions in the PNW are asserted in this proceeding. (CAL-1 at 2:19-23, 4:2-5, 5:5-9; Tr. 877:21-878:8; Tr. 880:9-15.) No other claims are asserted in this proceeding.

such purchases are the functional equivalent of other purchases made in the PNW by a Washington municipal utility or a California municipal utility.

In the August 9 "Order On Format For Data Submissions," it was ruled (slip op. at 8-9) that "all transactions which originate, are delivered, or must be transmitted in the PNW must be reported." Necessarily, this includes sales to CERS at PNW delivery points.

In the August 24 "Order On Motion To Strike Testimony," the TFG's motion to exclude CERS transactions was denied stating:

> *that bilateral transactions of the CDWR* in the PNW (as specified in the August 9 order) during the period at issue in this proceeding, *are relevant* to establishing a factual record concerning the volume of transactions, the identification of net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds, *as mandated by the Commission.*[54]

Finally, this order stated that it was "significant that the Commission in the July 25 Order, did not exclude CDWR from this proceeding," and ruled that "the Commission did not limit in any manner the identity of purchasers who may be eligible for refunds in the PNW."[55]

Thus the California Parties submit that the Commission has precluded recovery of refunds for bilateral purchases in California, but has never precluded recovery of refunds by California purchasers under bilateral contracts in the PNW. A contrary position

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[54] *Id.*, slip op. at 6 (emphasis added).

[55] *Id.*, slip op. at 7.

would create an arbitrary and capricious distinction between purchasers of wholesale electricity in the PNW who are physically located in that geographical region, and those physically located elsewhere. Simply stated, one group cannot receive the protection of just and reasonable rates, while the other does not.

TFG

The TFG argues, although the series of orders issued in the *San Diego* docket consistently define the spot market as the market for transaction of 24 hours or less, the July 25 Order questions whether the definition of spot market for the PNW may be different.[56] The evidence establishes that the appropriate definition of "spot market" in the PNW means one-time contracts for *immediate* delivery of electrical energy. An overwhelming majority of market participants have testified that "only transactions of no longer than 24 hours in length, entered into no more than 24 hours in advance [of delivery] . . . are spot market transactions." Exh. AU-1 at 4:62-64; *see also* Exh. ENR-1 at 8:22-24, 9:1-2; Exhs. ENR-26 through ENR-29.

According to TFG, in the PNW "spot market" means the sale of power for immediate delivery:

- "The definition of 'spot' transaction is typically defined to be transactions for immediate delivery, at prevailing prices." Exh. ENR-10 at 6:7-8; 8:13-16.
- "[A] spot market transaction in the [PNW] region [is] a transaction with a duration of 24 hours or less that is prescheduled no more than 24 hours in advance of delivery." Exh. AE-1 at 14:21-23.

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[56] 96 FERC at p. 61,520 at n.74.

- "[S]pot transactions are the result of a purchaser's need to buy elasticity on an immediate real-time basis. Thus, spot transactions have been for durations of 24 hours or less and have been consummated almost on an immediate basis . . . The only exception that is commonly accepted in the Western Systems Coordinating Council is in relation to the daily spot market. That exception occurs when the consummation of the transaction is intended to happen immediately after a weekend day, holiday, or a WSCC scheduler conference." Exh. IE-1 at 11:19-12:8.

- Spot market transactions are "[t]ransactions entered into with a duration of 24 hours or less . . . In the PNW and [WSCC] region generally, the spot market is limited to 24 hours sales. I am aware of no industry standard that considers transactions longer than 24 hours to be spot market transactions." Exh. RED-1 at 7:13-20.

- "The spot markets for the bilateral trading of electricity are understood to be the real-time and prescheduled or day-ahead markets." Exh. ENR-1 at 8:22-9:2.

"The key concept in the definition of spot markets and prices is 'immediacy.'" Exh. ENR-25 at 4:14-14.

- Spot market transactions "are entered the day-of or day-prior to delivery . . . are 24 hours or less . . . provide for deliveries in a specific hour or hours up to 24 hours in advance . . . [and] . . . [s]pot market contracts almost always go to delivery." Exh. PWX-1 at 24:9-19.

The correctness of this definition, TFG maintains, is evidenced by the multitude of similar industry definitions, as well as the definition used by the

Commission and its Staff. As the evidence shows, NYMEX, Bonneville Power Administration, the California ISO, and the Canadian NEB Electricity Trends and Issues all define "spot market" in terms of sales for "immediate delivery." *See* Exh. S-1 at 13:3-15:8; Exh. SMD-1 at 6:3-7:15; Exhs. ENR-26 through ENR-29. The Commission, itself in several orders in the EL00-95 docket, has defined "spot market" as sales that are 24 hours or less, which are entered into the day of or day prior to delivery.[57] Furthermore, the Commission's Staff has previously defined "spot market" for purposes of electricity sales as "[a] market where goods are traded for immediate delivery." Exh. TFG-26; *see also* Tr. at 1222:25-1230:8.

Thus, "immediate delivery" is an important criterion of many spot markets. As noted by Mr. Adamson, electricity is deliverable immediately, unlike other commodities such as coal, which is typically shipped in vast quantities by train, barge or ship. Exh. ENR-25 at 3:

> Electricity is delivered simultaneously with production, via the high voltage transmission system. For this reason, spot market definitions for electricity are generally defined (such as the Real-Time Market of the California ISO referred to by Ms. Tingle-Stewart at 16) as operating on very short-time horizons. As delivery is instantaneous in electricity, the defining characteristic of electricity spot market transactions is the timing of scheduling of transactions. The underlying scheduling process

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[57] *See, e.g.*, June 19 Order at p. 62,545 n.3 ("As used throughout this document, the terms 'spot markets' or 'spot market sales' means sales that are 24 hours or less and that are entered into the day of or day prior to delivery.").

> for delivery in the PNW operates on a daily basis. This supports my fundamental conclusion that a 24-hour or less ahead (with weekend, holiday and WSCC scheduler conference exceptions) definition is the appropriate one for the PNW bilateral spot market in electricity.
>
> Exh. ENR-25 at 3.

Cross-examination of witnesses supporting this view only bolsters this point that TFG asserts. For example, Mr. Adamson testified:

> [M]y judgment about the appropriate definition of the spot market really had two components, an economic one and a practical one . . . . In terms of the practical one, . . . how I tried to verify my understanding of the market, . . . I conducted a telephone survey with four traders, [and] [t]here's also kind of an e-mail survey that went out. . . . [From that,] it is my conclusion, as I describe in my rebuttal testimony on page 4, that the 24-hour-or-less market meets the correct economic definition of a spot market.

Tr. at 1112:10-1113:3. Likewise, Mr. Van Vactor testified:

> [T]he opinion we're trying to offer [about the definition of spot market] is based on our experience in other markets, our experience in other regions and so on and so forth, [all of which] gives a fairly objective definition of what the spot market is. And it is by and large, across a whole set of markets, a daily market. It is not a year-long [or] month-long market.

Tr. at 1116:9-16. When pressed further about the differing view of the Bonneville Power Administration's ("BPA") witness, Mr. Adamson responded:

> I do not [agree with the definition of spot market transactions used by Stephen Oliver, witness for the BPA]. Mr. Oliver would treat within-the-month and balance-of-month transactions [as] spot transactions, claiming these are not discretionary in nature . . . . However, this distorts the definition of spot which centers [not] on whether . . . the transaction is discretionary but rather whether or not [the transaction] is for immediate delivery.
>
> Tr. at 1118:11-25.

In contrast to the testimony that "spot market" concerns sales for immediate delivery, the testimony of the claimants' witnesses was unsupported by any structural justification, trade practice or practical distinction according to TFG. *See, e.g.*, Tr. at 576:4-14 (under definition espoused by City of Seattle, "all of Seattle City Light's transactions between December 25, 2000 and June 19, 2001 are considered spot market . . . purchase transactions"). Even Ms. Tingle-Stewart, the Staff's witness who advocated an expansive definition of "spot market," stated on cross-examination that "spot market" for purposes of this proceeding cannot, by definition, include all sales transactions. Tr. at 1214:22-1215:22. Ms. Tingle-Stewart further stated that "typically [a] spot market is usually 24 hours or less" and identified no structural distinctions of the PNW markets that would justify a definition different than the "typical" one. Tr. at 1215:20-22.

If the Commission had intended to conduct an inquiry into the prices charged for all transactions in the PNW, it could readily have done so; instead, it limited the inquiry to "spot market" transactions TFG avers. Its guidance should not now be discarded to sweep in nearly all transactions under the rubric

of an artificially expanded definition. The testimony of Dr. Tabors shows that by expanding the definition of spot market to include contracts of a year or more, these claimants increased their potential claim by a magnitude of more than ten:

> My Exhibit PWX-13 quantifies the impact of applying this definition [of spot market] to the refund claims of . . . NPG entities who are serving load in the Northwest . . . . This exhibit shows that *94%* of these NPG claims are eliminated if the proper definition of a spot market transaction is applied as a screen to their purchase data during the potential refund period (December 25, 2000 through June 20, 2001). This reduces the total claims . . . from *$460,668,382* to *$25,410,505*.

Exh. PWX-12 at 5:12-18 (emphasis in original); *see also* Exh. TFG-23A. Dr. Tabors again notes this correlation:

> It is interesting to note that only 1% of Seattle City Light's proposed refunds are attributable to its spot purchases and well less than 40% of Tacoma's refunds are due to its spot purchases. *Thus, the bulk of the refunds they are seeking are attributable to the prices they paid under their forward contracts!*
>
> Exh. PWX-1 at 23:6-9 (emphasis in original).

Additionally, TFG argues, NPG asserts that the cross-examination of NPG witness Ms. Green revealed the existence of important differences between daily market transactions and month-ahead or longer transactions: "Under traditional practice, none of the hourly transactions are [sic] recorded on paper. There simply isn't time to deal with that. . . . [In contrast,] monthly deals do have written confirmation." Tr. at 582:14-16, 1-4. Ms. Green also admitted that

the City of Seattle has different personnel assigned to the "forward" desk to conduct these different functions. Tr. at 580:9-581:19. The Deputy Director of California Department of Water Resources, who professed "quite extensive" on-the-job experience, defined spot market as "normally 24 hours or less." Tr. at 986:9-10; 898:14-18; *see also id.* at 902:21-904:3; 916:6-917:3.

Dr. Tabors explained that spot market contracts and forward contracts have different characteristics. He corrected the Staff's contention that spot market could mean up to one year:

> Staff has focused on price to the exclusion of all other contract terms and conditions, such as quantity and availability of supply. For example, as I stated in my responsive testimony, the fact that a forward contract has an indexed price does not serve to convert the forward contract into a spot contract.
>
> Exh. PWX-12 at 9:13-16.

In further support of its contentions, TFG avers that Mr. Stelzer, trading manager of Avista Energy's power trading activities, explained that "the bilateral wholesale electric market is broken down into the term (or forward) market and the spot market which encompasses the day-ahead and real-time market." Exh. AE-1 at 7:15-17. He described the types of products in the forward market which are not considered spot but which are for delivery terms of greater than 24 hours. "This [forward] market includes: weekly products, balance-of-the-month products, monthly products, quarterly products, annual products and multi-year products." Exh. AE-1 at 7:21-22.

Dr. Tabors' testimony illustrated the significant differences between spot market transactions and forward contracts:

> A spot market bilateral contract for electricity differs from a forward market bilateral contract for electricity in many respects, and therefore represents a different "product" from the perspective of both a buyer and a seller. These differences include:
>
> • Timing of the contractual commitment. Spot market transactions are entered the day-of or day-prior to delivery, forward market transactions may be entered days to years prior to delivery.
>
> • Duration of the commitment. Spot market transactions are 24 hours or less, forward market transactions may be for multiple years.
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> • The hours in which electricity will be delivered. Spot market transactions provide for deliveries in a specific hour or hours up to 24 hours in advance. Forward market transactions provide for deliveries in blocks of heavy load hours (HLH), light load hours (LLH) or all hours (flat) for durations of balance of month, month, quarter, annual or multiple years.
>
> • [Physical Delivery.] Spot market contracts almost always go to delivery whereas forward contracts can be, and frequently are, traded several times prior to delivery. This ability to trade forward contracts gives their buyers the ability to continuously "fine tune" their portfolio of advance supplies to match changing expectations regarding their actual requirements and the availability of other resources to meet those requirements.

As a result of these key differences, the value of electricity under each type of transaction will be different. The Commission recognized the differences in value between spot market transactions and forward market transactions in its December 15 Order. Thus, it is unlikely that in any given hour a buyer with a portfolio of contracts will be paying the same price for electricity bought under a bilateral spot market contract as it is paying for electricity bought under a bilateral forward contract, even if it is buying the identical quantity in each market in a given hour from the same seller. Exh. PWX-1 at 24-25.

According to TFG, Mr. Stelzer further distinguished a spot market contract from a forward contract with a pricing mechanism indexed or referenced to spot prices:

> Volume and other essential terms in an indexed contract are decided on a long-term basis and the buyer has simply and voluntarily chosen a pricing option (one among many) in a long-term contract which has some reference to the spot market. Where a buyer elects to have its purchases under a long-term contract indexed to the spot market, the buyer may believe that the price for this product in the forward market is higher than what the price of the spot market will be when the electricity is actually delivered. Alternatively, the buyer may not be concerned so much about price as it is about electricity not being available when it comes time to buy . . . and elects to lock-in delivery under the forward contract.

Exh. AE-1 at 10:16-11:2. Finally, Mr. Oliver from BPA, in describing the contract underlying the refund claim of Northern Wasco County People's Utility District ("Northern Wasco") explains:

> Northern Wasco elected . . . to serve approximately 30% of its firm load needs through a surplus firm power sale agreement providing for the purchase of a cost-based product that had a price tied to the Mid-Columbia Index . . . because they thought this rate would be lower than the cost-based federal power over the long run. These contracts are not spot market transactions. They are long-term firm power contracts that were indexed to spot market, at the election of Northern Wasco.
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> Exh. BPA-1 at 8.

Evidence of record, TFG maintains, confirms the customary and proper definition of "spot market." It means sales for immediate delivery; it is distinct from other products. Immediate delivery in the PNW is defined by scheduling practices. Thus, TFG alleges, the evidence demonstrates that for the PNW wholesale electrical market, "spot market" sales are those sales made 24 hours or less in advance of delivery for a duration of 24 hours or less, except for holidays, weekends or scheduling coordinator conferences, but delivery is nonetheless scheduled immediately. No other reasonable or credible definition has been established.

TFG also argues that both the evidence and the issues stipulated establish that the region specified by the Pacific Northwest Electric Power Planning and Conservation Act is the pertinent geographic market. That market is:

> (A) the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and

> (B) Any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A) which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980 which has a distribution system from which it serves both within and without such region.

16 U.S.C. § 839a(14).

According to TFG, the testimony presented here establishes that this definition informs and guides the conduct of market participants. This is the same definition that Puget used in its Complaint initiating this proceeding. *See* Exh. ENR-1 at 4:19-5:3. As Mr. Van Vactor explained, "[t]his definition of the PNW power market is the most consistent and useful [because it] both matches the operational characteristics of the power system and waterways and also conforms to the existing political organization of the region." *Id.* at 5:14-18. Mr. Van Vactor explained that, the NW Power Planning Act defined market is the appropriate choice here because it:

> encompasses the entirety of the U.S. portion of the Columbia River drainage basin, which is the principal source of generation for the Northwest's utilities, a major transportation waterway, the most important source of irrigation supporting the region's agricultural industry, and a key natural resource for recreation and preservation of wildlife. In short, the management of rivers and the coordination of hydroelectric generation are activities that necessitate region-wide planning and cooperation for the states adjacent to the Columbia River, but need not involve other parts of the western region. In addition, the NW Power Planning Act established the Northwest Power Planning Council with

representatives appointed by the Governors of Idaho, Montana, Oregon, and Washington. The Council is responsible for preparing Northwest Power Plans at least every five years. The most recent was completed in 1998. The principal reasons for these plans are to ensure that generating resources and loads in the region are balanced cost effectively, energy conservation programs are implemented, and, recently, that wild salmon runs on the Columbia River and its tributaries are preserved and enhanced.

Id. at 5:19-6:10.

As Mr. Van Vactor further explained, the testimony suggesting a geographic definition other than that prescribed by NW Power Planning Act is misguided:

> The justification of City of Seattle's witness, Robert McCullough, for using a broader definition, the Northwest Power Planning Pool ("NWPP") as opposed to the "PNW" in the NW Power Planning Act is problematic. Parts of the NWPP are more heavily traded by Southwest and Southern California utilities than by Northwest utilities. The Intermountain Power Project, for instance, sends a substantial amount of power (approximately 1,500 MW per hour) to the Los Angeles control area even though it is located in Utah, and hence is in the NWPP.
>
> Furthermore, all of the PNW refund proponents are located within the territory governed by the NW Power Planning Act (with the obvious exception of the California parties who are decidedly not PNW utilities); thus, adopting the broader definition of the NWPP would unnecessarily expand the

investigation envisioned by the evidentiary hearing.

Exh. ENR-1 at 6:13-24.

TFG further maintains, notably, as Mr. Ali Yazdi explained, the definition of PNW "should be qualified as a practical matter to exclude southbound transactions at the COB and NOB delivery points for CDWR's account." Exh. PWX-7a at 5:16-18. This is because

> [t]hese transactions are really transactions for California loads that happen to specify a delivery point at the PNW-California boundary. The PNW delivery point in the case of CDWR transactions was based on transmission rather than load-serving considerations.

Id. at 5:18-6:2.

California Parties' witness Mr. Green of the California Energy Resource Scheduling Division ("CERS")[58] also admitted that COB deliveries in reality are made at the California border and that the ISO tariff specifies scheduling points for such deliveries as "Malin-[Oregon]", "Round Mountain [California]" and "Captain Jack [Oregon], Olinda [California]." Tr. at 876:3-12. Mr. Green also testified that NOB is an "imaginary" point and that NOB deliveries actually take place in California at the control area of the Los Angeles Department of Water and Power. Tr. at 876:16-25.

In further support of its arguments, TFG points out that no one seriously disputed the definition of the

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[58] CERS is a division of the CDWR that is authorized by California statute "to purchase electric power and sell power to retail end use customers and to locally publicly owned electric utilities." Exh. CAL-1 at 3:8-9.

PNW at the hearing. Cross-examination of Mr. Van Vactor and the other witnesses expressing the same geographic market definition did not in any way undermine their view or the logic of it. The Staff witness testifying as to market definitions similarly offered no contrary view of the proper geographic market:

> As stated in the Commission's June 19, 2001 Order and as stipulated by the parties in the instant proceeding (this portion of the Stipulation was incorporated in the Presiding Judge's August 23, 2001, order on issues), the Pacific Northwest is defined in the Pacific Northwest Electric Planning and Conservation Act, 16 U.S.C. § 839a(14). Exh. S-1 at 8:5-8.

Therefore, according to TFG, the evidence proves that the correct definition of the PNW is the geographic region defined in the NW Power Planning Act and that southbound flows at COB and NOB are not sales "into" the PNW, but into California. Thus, these California transactions should not be considered in this PNW proceeding, as discussed in detail in Section V of this brief.

Concerning the refund claims of the California Parties TFG avers that the California Parties[59] have made refund claims on behalf of the CDWR, which does not itself seek refunds. Tr. at 843:11-23. The California Parties base these claims on CDWR purchases and exchanges under bilateral agreements (not limited to spot market transactions) which they

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[59] Nominally, the California Attorney General ("CAG"), the California Public Utilities Commission ("CPUC") and the California Electricity Oversight Board ("EOB").

allege to have occurred in the PNW during the potential refund period.

The TFG opposes these refund claims. The California Parties' claims have already been rejected by the Commission in Docket No. EL00-95 and do not reflect the stated position of CDWR, the entity on whose behalf they are ostensibly being brought. TFG believes that the California Parties' claims have no place in this proceeding. If these claims are considered at all in Docket No. EL01-10, they should be disallowed.

This preliminary evidentiary proceeding was intended by the Commission to give PNW parties claiming refunds or asserting offsets in Docket No. EL00-95 additional process to demonstrate whether their claims warranted further proceedings. TFG argues, unlike the PNW parties, the California Parties fully ventilated their refund claims in Docket Nos. EL00-95. The Commission was unpersuaded, and expressly denied relief for CDWR's bilateral purchases on both legal and equitable grounds.[60]

The TFG sought to strike the California Parties' direct case,[61] but the Presiding Judge gave the California Parties an opportunity to participate in the hearing.[62] The Presiding Judge now has an evidentiary record upon which to make a preliminary ruling on the California claims and give effect to her earlier warning that "California refunds are being litigated

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[60] July 25 Order, 96 FERC at pp. 61,514-515.

[61] Motion of the Transaction Finality Group to Strike Testimony of California Parties, Docket No. EL01-10 (August 22, 2001).

[62] Order on Motion to Strike Testimony, Docket No. EL01-10 (August 24, 2001).

in a separate proceeding, EL00-95-031, *et al.* TFG contends."[63]

By order dated August 8, 2001, the Presiding Judge aligned the following five California parties with the Pacific Northwest Net Purchasers Group ("NPG"): the CAG, the CPUC, the California Independent System Operator ("CAISO"), the EOB and Southern California Edison Company ("SCE"). Another California Executive Branch entity (CDWR —the real party in interest under the bilateral agreements), never sought to intervene in this proceeding.[64] Ultimately, only three of the five named "California Parties"—the CAG, the CPUC, and the EOB—were part of the group's August 17, 2001 affirmative case filing.

According to TFG, the California Parties allege that a total of $2.64 billion of purchases by CDWR falls within the scope of this Docket No. EL01-10 proceeding, of which they claim $1.47 billion in refunds. To support this claim, the California Parties presented testimony of one fact witness, William Green, and one economic witness, Dr. Frank Wolak. Mr. Green, an employee of the California Energy Resources Scheduling ("CERS") Division of the CDWR, testified that the entirety of the California Parties'

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[63] Order on Format for Data Submissions, Docket No. EL01-10 at 8, n.7 (August 9, 2001).

[64] CERS is not an intervenor either. As a division of CDWR, CERS has no separate legal standing. CDWR itself, not CERS, is the member of WSPP and signatory to the contracts and Transaction Confirmations at issue in this proceeding. CERS may have scheduled deliveries under these agreements (in improper concert with the ISO), but CDWR is the real party in interest in this proceeding.

claim was based on bilateral purchases made by a single entity, the CDWR.

In his direct testimony, and again at hearing, Mr. Green stated that he had aggregated, for refund claim purposes, *all* transactions (including longer-term arrangements, fixed price arrangements, aggregation or "sleeving" arrangements, and exchanges) where California took power at one of its interconnects with the PNW. According to Mr. Green, CDWR treated all these transactions as spot market transactions under the Staff's template definition, based on the time the deliveries were scheduled (*i.e.*, day-ahead or in real-time), without regard for the related contracts, Transaction Confirmations or negotiated arrangements under which such deliveries occurred, or indeed, for the duration of the transactions themselves. *See* Exh. CAL-1 at 5.

Dr. Wolak's testimony, TFG avers, summarized the California Parties' position on the appropriateness of refunds for these transactions. Dr. Wolak opined that refunds should be considered for all transactions up to two years in duration. In addition, Dr. Wolak also made generalized allegations that sellers had exercised market power, but neither he nor any other California witness provided any evidence of actual or attempted exercise of market power by any seller in the PNW.

On rebuttal, the California Parties supplemented the additional testimony of Mr. Green with one additional fact witness, Mr. Raymond Hart, the Deputy Director of CDWR and the Director of CERS during the potential refund period, and one additional economic witness, Dr. Carl Pechman. According to TFG, Mr. Hart detailed CDWR's version of the events surrounding the agency's purchases (principally from

Powerex Corp. ("Powerex"), a TFG member) in early 2001, and discussed the credit and payment terms insisted on by Powerex. Dr. Pechman attempted to refute the testimony of the TFG's experts, who had testified why, for economic and policy reasons, refunds are not appropriate for the bilateral purchases which fall within the scope of this proceeding. Dr. Pechman also made unsubstantiated assertions regarding in elasticity of demand, even though he admitted he had performed no studies in that regard. In fact, demand in the PNW behaved in just the opposite fashion from what he suggested. Mr. Green, Mr. Hart and Dr. Pechman were all cross-examined at hearing by the TFG and others.

According to TFG, there is abundant record evidence in this proceeding showing not only that sales to CDWR should not be considered in this proceeding along with true PNW transactions, but also that the CDWR transactions upon which the California Parties have based much of their refund claims, are not spot market bilateral sales. This evidence, discussed in detail below, clearly supports a finding by the Presiding Judge that the refunds sought by the California Parties should be disallowed.

TFG argues that the Commission's refund authority in Docket No. EL01-10 is constrained under Section 206 of the Federal Power Act by the date and substance of Puget's October 26, 2000 complaint.[65] Puget's complaint was expressly limited to contracts for sales *into* the PNW market:

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[65] July 25 Order, 96 FERC at p. 61,520 n.75 ("December 25, 2000 is the earliest refund effective date the Commission could establish for Puget's complaint regarding rates in the Pacific Northwest").

> [T]his Complaint seeks an order affecting the market-based rate schedules of wholesale sellers of energy and/or capacity *into* electric energy and/or capacity markets in the Pacific Northwest . . . (Complaint, at 1) (emphasis added).

By formal notice issued October 31, 2000, the Commission identified Puget's complaint as addressing the prices at which sellers "may sell capacity or energy *into* the Pacific Northwest's wholesale power markets."

In orders issued in EL00-95, the Commission has clearly and carefully delineated the scope of its refund authority:

> We conclude that FPA Section 206 does not permit the Commission to require refunds of unjust and unreasonable rates charged prior to a date 60 days after the filing of a complaint or 60 days after the initiation of a Commission investigation on its own motion. To order such refunds would contravene explicit refund limitations that Congress put in FPA section 206.[66]

No complaint has ever been filed with the Commission, nor has any notice ever been issued by the Commission, stating that *any* sales under CDWR's bilateral contracts may be subject to refund prior to June 20, 2001. Under the Commission's June 19, 2001 order in Docket No. EL00-95, only CDWR spot market transactions were made subject to market mitigation (along with all other bilateral spot market transactions in the WSCC) prospectively from June 20, 2001. The extension of Docket No. EL01-10 to include CDWR's bilateral contracts—contracts for sales of energy or capacity *into California*—would

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[66] July 25 Order, 96 FERC at p. 61,504.

constitute an unlawful extension of the Commission's Section 206 refund authority. Recognizing this in its July 25 Order, the Commission invited CDWR to file its own Section 206 complaint in the event it wished to contend that its bilateral contracts were unjust and unreasonable.[67] CDWR has not done so. Thus under Section 206 of the FPA, there is no legal basis for the Commission to order retroactive refunds with respect to CDWR's bilateral transactions.

In its July 25 Order, the Commission flatly refused to order refunds with respect to CDWR's bilateral agreements. The Commission concluded that:

> . . . imposing after-the fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding [Docket No. EL00-95] when the Commission consistently encouraged California load-serving entities to acquire a balanced portfolio of short, medium-term and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000 through June 20, 2001 to include transactions outside the ISO and PX markets would simply hinder the ability of parties to enter into new bilateral contracts.[68]

Until this PNW hearing in Docket No. EL01-10 was initiated, there was no suggestion whatsoever from the California Parties that CDWR's bilateral transactions were anything other than California transactions subject to the proceedings in Docket No. EL00-95. Since the Commission expressly determined in the July 25 Order that refunds under CDWR's bilateral agreements were unjustified, it inexorably

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[67] 96 FERC at p. 61,515 n. 59.

[68] 96 FERC at p. 61,515.

follows as a matter of law that CDWR's bilateral contracts with PNW sellers for deliveries to points on the boundaries of the PNW and California, for consumption within California, cannot be subject to refunds in Docket No. EL01-10.

The California Parties' attempt to repackage selected CDWR transactions into a new PNW category is belied by their own pleadings in the two dockets, TFG argues. In its July 30, 2001 rehearing request (filed in Docket No. EL00-95 one day before the first prehearing conference in Docket No. EL01-10), the EOB sought reversal of the Commission's decision in Docket No. EL00-95 to deny refunds with respect to all CDWR bilateral spot market transactions. In its rehearing request, the EOB drew no distinctions whatsoever based on the point of delivery or the point of origin. Table 2 of the EOB's rehearing request referred to CDWR's alleged January 2001 purchases from PNW Parties (including TFG members Avista, Coral Energy and Powerex Corp.) as justifying a retroactive refund finding by the Commission on rehearing.[69] Plainly, EOB viewed these CDWR bilateral transactions with PNW parties as being within the scope of the Commission's ruling denying refunds in Docket Nos. EL00-95. Otherwise, EOB would not have included them in its rehearing request.

The California Parties cannot have it both ways, TFG maintains. In Docket No. EL00-95, EOB and the other California Parties repeatedly asserted refund claims based on the totality of the CAISO, California PX and CDWR transactions from May 1, 2000 to date. All of these transactions were subsumed

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[69] See EOB Rehearing Request, Docket Nos. EL00-95 et al., at 14 (July 30, 2001).

in Governor Davis's $8.9 billion refund claim, which was asserted in the settlement discussions before Judge Wagner by Michael Kahn, Chairman of the ISO, speaking on behalf of CDWR, the CAG, the CPUC and the EOB, among others. The only rational way to harmonize the Commission's July 25th Order —which on one hand expressly denies refunds for CDWR's bilateral transactions and directs CDWR to file a complaint if it has a problem, and on the other hand establishes a preliminary evidentiary proceeding to review potential refund and payment claims by PNW parties—is to construe the Docket No. EL01-10 proceeding as excluding CDWR bilateral transactions, and as being limited in scope to the transactions addressed in Puget's original complaint.

There is also no factual basis for considering CDWR's transactions in this PNW-specific preliminary evidentiary proceeding. The Commission's sole purpose for instituting this hearing was to give PNW Parties that participated in the June 25-July 9 settlement discussions before Chief Judge Wagner "additional process" to discuss amounts owed and refunds claimed to be due to them. As Judge Wagner noted in his July 12, 2001 report to the Commission,[70] these settlement discussions dealt almost exclusively with California refund claims—*including* refund claims regarding CDWR bilateral purchases.[71]

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[70] *San Diego Gas & Electric Co., et al.*, 96 FERC ¶ 63,007 at p. 65,039 (2001).

[71] The California Parties (and other California entities such as the CAISO, Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company) operated as a separate and distinct group throughout these settlement discussions, and were not treated by Judge

The Commission has made its intent abundantly clear in the July 25 Order:

> The Chief Judge noted that there was little time to address the issues raised by the Pacific Northwest Parties. Moreover, these parties did not have data on what they claim they were owed, nor on an amount of refunds due them. The Chief Judge requested comments on the necessity of convening subsequent settlement conferences to address the issues. Comments jointly filed by the Pacific Northwest Net Purchasers state that there was inadequate time either to document the harm suffered, or to engage in meaningful settlement discussions with affected sellers. Given these circumstances, they request additional process on this matter.[72]

As counsel for PacifiCorp, speaking on behalf of the Pacific Northwest Net Purchasers Group, stated to Judge Wagner in a public hearing held late on July 9, the last day of the settlement conferences:

> We respectfully request that as part of your recommendations, that the Commission find a way to extend the proceedings so that Northwest refunds can be considered in parallel to those enjoyed by consumers in the State of California.[73]

There is nothing in the record that Judge Wagner compiled, in Judge Wagner's Report, or in the Commission's discussion of the Pacific Northwest proceeding in the July 25 Order to suggest that the Commis-

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Wagner or the other parties as being associated in any way with Pacific Northwest issues.

[72] 96 FERC at p. 61,520.

[73] July 9, 2001 Hearing in Docket Nos. EL00-95 *et al.*, Hearing Tr. 682.

sion intended for CDWR bilateral transactions for which refunds were denied in Docket No. EL00-95 to be revisited in Docket No. EL01-10. On the contrary, the Commission took pains to distinguish this Pacific Northwest proceeding from the California proceedings:

> In light of the complexities associated with these retroactive bilateral calculations and the absence of any further development of this issue in the settlement proceeding, and in recognition that the prior settlement proceeding focused primarily on California, *we will establish a separate preliminary evidentiary proceeding pertaining to the Northwest.*[74]

In furtherance of its contentions, TFG argues that CDWR was authorized by California statute[75] in February 2001 to begin purchasing electric power to sell to retail end-use customers *in California* and to make purchases on behalf of the three *California* IOUs, including their net short position.[76] Exh. CAL-1 at 3. There is no suggestion in the record that CDWR has been anything other than a purely California entity since it commenced operations. By no stretch of the imagination could it be considered to be a PNW party.

Since January 17, 2001, CDWR has been the power procurement agency for the state of California. Tr. at 808:19-09:8. The agency makes purchases solely for California entities. It does not make purchases for

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[74] 96 FERC at p. 61,520 (emphasis added).

[75] This enabling legislation for CDWR's power procurement function is known as "AB-1X," and is contained in Exh. TFG-14. AB-1X makes no mention of CERS.

[76] 2000 Cal. Legis. Serv. 1ES 4 (West) § 80100 *et seq.* ("AB-1X)", TFG-14, at 6.

consumers outside California. Tr. at 875:10-12. It maintains no offices or operations in the PNW. Tr. at 874:20-75:5. CDWR does not contract for transmission in the PNW or anywhere outside of California.[77] Tr. at 895:2-7. Its sole nexus to the PNW is that certain of its transactions specify delivery points at interconnects on the boundaries of the PNW with California (COB, NOB, Cascade and Summit). Tr. at 877:21-878:1. However, CDWR actually takes physical delivery of its purchases at substations located *within California* "Malin-5-Round Mountain" and "Captain Jack-5-Olinda" in the case of COB, and a substation within LADWP's control area in the case of NOB. Tr. at 875:19-877:3. In short, there is no factual basis to conclude that CDWR is a PNW party entitled to have its claims considered in Docket No. EL01-10.

All purchases that the California Parties have categorized as PNW purchases were made under the framework of the WSPP Agreement. Tr. at 889:8-12. CDWR is a member of the WSPP. Tr. at 890:25-891:1. The terms of the WSPP Agreement have been reviewed and approved by the Commission. Tr. at 891:2-6. Section 35 of the WSPP Agreement specifically provides that all transactions under the WSPP Agreement, together with the confirmation agreements executed pursuant to its terms, are considered forward contracts. Exh. S-6 at Original Sheet 56; Tr. at 890:13-18.

The Commission has ordered that the PNW transactions to be examined in this proceeding are limited to spot market bilateral sales in the PNW.[78] TFG

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[77] This is LADWP's Sylmar Substation.

[78] July 25 Order, 96 FERC ¶ 61,120 at slip op. p. 44.

further argues, that notwithstanding that all transactions entered into under the umbrella of the WSPP agreement are considered forward contracts, the California Parties apparently allege that all transactions that CDWR entered into under the umbrella of the WSPP Agreement in fact constitute spot market purchases.[79] Thus any transaction *scheduled* by CDWR within 24 hours of delivery (which would encompass literally any delivery under a forward contract) has been treated by the California Parties as a spot market purchase, without regard for either the WSPP Agreement, when related Transaction Confirmations under the WSPP Agreement may have been entered into, or the nature of the ongoing relationships between CDWR and its counterparties. This severely distorts and inflates the extent of the California Parties' claimed refunds.

For example, TFG avers, Dr. Tabors analyzed CDWR's data regarding purchases from Powerex (which accounts for more than a third of the California Parties' refund claims), and applied a proper definition of a spot market transaction as a filter for such data (transactions of 24 hours or less, entered into the day of or day prior to delivery). Dr. Tabors showed that applying this definition to CDWR's data reduced the California Parties' refund claims against Powerex by 86 to 90 percent, from $568,240,374 to between $57 million and $80 million. Exh. PWX-12 at 6-7. Dr. Tabors did not have time under the compressed procedural schedule to perform this calcula-

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[79] If the California Parties are not in fact calling such transactions "spot market" transactions, then they are simply disregarding yet another clear dictate of the July 25 Order, which limited the scope of this proceeding to spot market bilateral sales.

tion with respect to CDWR's refund claims against other sellers, but TFG notes that the California Parties did not question Dr. Tabors' conclusions on cross-examination.

The validity of the California Parties' claims is further compromised by their inconsistent and conflicting positions regarding what constitutes a spot market transaction—a core issue in both the PNW and California dockets, TFG asserts. For example, in the EOB's July 30, 2001 request for rehearing in Docket No. EL00-95, the EOB acknowledged that CDWR defines the spot market as "day-ahead purchases, hour-ahead purchases, and ISO real-time purchases."[80] In contrast, Dr. Frank Wolak, the California Parties' expert witness in EL01-10, although not directly addressing the issue of what constitutes a spot market, opined that for litigation purposes the "appropriate time horizon . . . that a bilateral sale of electricity in the Pacific Northwest market that should be subject to refund is as long as two years in advance of the delivery date."[81] Exh. CAL-5 at 4.

Mr. Green, according to TFG, also put forward shifting definitions of the spot market, and created further confusion regarding the true nature of the

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[80] Request of the California Electricity Oversight Board for Expedited rehearing of the July 25 Order Establishing Evidentiary Hearing Procedures, Docket Nos. EL00-95-004 *et al.*, at 13 n. 7 (July 31, 2001).

[81] Dr. Wolak stops short of calling such transactions "spot market" transactions and instead speaks in terms of transactions that "should" be subject to refund. The July 25 Order did not, however, invite such an inquiry into what "should" be subject to refund. Instead, the order referred specifically to potential refunds in connection with *spot market* transactions. July 25 Order, 96 FERC at p. 61,520.

transactions reflected in his Exh. CAL-11 and associated confidential workpapers. ***(Confidential Exhibit TFG-19 in the case of CDWR transactions with Powerex, a TFG member)*** Mr. Green in his direct testimony originally stated that "almost all our purchases were for 24 hours or less." Exh. CAL-1 at 4. Mr. Green then went on to list the "aggregate" CDWR transactions that occurred at PNW delivery points. Mr. Green broke out these transactions by Out Of Market ("OOM"), Day-Ahead and Long/Short categories, with the preponderance of claimed refunds arising from the OOM category of transactions. The inference created by Mr. Green's testimony was that most of the OOM transactions were periods of 24 hours or less, and hence were eligible for refunds. However, on cross-examination Mr. Green qualified his testimony by stating that he "normally" defined "spot market transactions" as "24 hours or less," Tr. at 898:17-18, and then went on to relate his categorizations of CDWR transactions to the Staff's data template (which was not intended to define the term "spot market") rather than to any assessment of the actual character of the transactions themselves. Tr. at 902:21-903:1. On redirect, Mr. Green tried to conform his testimony and the workpapers to the California Parties' position in EL01-10, by stating that "[W]hen there's conditions such as shortness of supply, a spot term might be quite a bit longer than 24 hours or one day . . . Could be the balance of the month or a whole month or longer. . ." Tr. at 981:1-6.

TFG contends that the inflated data, conflicting positions of the California Parties, and vagueness of Mr. Green's testimony fatally undermine the factual basis for their refund claims. These defects in CDWR's claims, TFG argues, render Mr. Green's

testimony and exhibits unreliable and non-probative. The only conclusions that the Commission can draw are that the California Parties have failed to provide probative evidence to support their refund claims and meet their burden of proof in this proceeding, and that their proposed definition of the "spot market" is inconsistent with the overwhelming weight of the evidence in the record.

According to TFG, the California Legislature, in enacting AB-1X, gave CDWR the sole authority to determine the justness and reasonableness of its power purchases under Section 451 of the Public Utility Code of California, without review by the CPUC or any other regulatory body.[82] The CPUC has expressly acknowledged that "contracts for and purchases of power by DWR and related indebtedness are not subject to [CPUC's] reasonableness review." Exh. TFG-15 (CPUC Decision No. 01-03-009, March 7, 2001). On cross-examination, Mr. Hart confirmed that CDWR is self-regulating with respect to its purchasing activities. Tr. at 840:12-17.

As noted above, CDWR itself does not seek refunds in this proceeding. Also, CDWR has not filed a complaint at FERC regarding any of its bilateral purchases, nor has CDWR issued any notice of potential refunds under AB-1X with respect to its purchases.[83]

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[82] *See* AB-1X § 80110; *see also* Exh. TFG-14 at 7-8.

[83] Under the same principles that constrain FERC, CPUC regulatory actions under Section 451 of the California Public Utilities Code are subject to the filed rate doctrine and prohibitions against retroactive ratemaking. *Pacific Tel. & Tel. Co. v. Public Util. Comm.*, 62 C.2d 634 (1965). Since AB-1X confers this same Section 451 rate review authority on CDWR with respect to its purchases, the same ratemaking standards apply to CDWR.

Instead, Mr. Hart, as "fact witness" for the California Parties, has only offered his personal opinion that CDWR had "no choice" but to purchase power from PNW sellers such as Powerex, Exh. CAL-9 at 2, 3, 6, paid too much for the power, *see, e.g.*, Tr. at 897:19-21, and paid prices for power that reflected sellers' "opportunity costs to make a fortune off some poor chump like me." Tr. at 947:23-24. Recross of Mr. Hart demonstrated that he is not qualified to testify as an economic expert on the subject of market power. Tr. at 985:21-987:11. The California Parties' economic expert, Dr. Wolak, made only generalized allegations of exercise of market power by sellers in California and the PNW, but offered no proof whatsoever in support of his assertions.

Thus, reduced to its essence, the California Parties' refund case is based on Mr. Hart's assertions that he paid too much to sellers, even though his employer, CDWR, does not itself seek refunds for the purchases Mr. Hart and his staff made. Mr. Hart is entitled to his observations, but they do not constitute evidence that the prices CDWR paid for power purchased from PNW sellers during the potential refund period were unjust and unreasonable.

To the contrary, TFG asserts, there is ample record support justifying the prices paid by CDWR to PNW sellers. Because of the circumstances it confronted in California,[84] CDWR, a state agency, found it necessary to purchase large, even huge, blocks of power on a recurring basis to meet peak and super-peak needs, and in so doing had to draw on other utility systems

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[84] The factors that led to CDWR's demand for power are chronicled by Powerex's witness Mr. Peterson in Exh. PWX-6 at 11.

outside of California to meet demand. In the PNW, for example, CDWR relied on the ability of hydroelectric systems such as those operated by BPA and BC Hydro (Powerex's parent) to produce large blocks of power on short notice. Tr. at 892:23-893:12.

Through these arrangements, CDWR was able to purchase blocks of power as much as 2,000 MW to 3,000 MW, and to purchase large blocks of power on a recurring basis throughout the refund period. Tr. 893:17-21.

What Mr. Hart failed to point out is that the ability of hydropower generators to provide these large blocks of power on short notice is not infinitely elastic, and involves considerations of opportunity costs and the cost of replacement power, TFG contends. In his Prepared Responsive Testimony on the Nature of Hydroelectric Power, Dr. Tabors discusses in detail how hydropower systems operate, including their ability to ramp unit output up and down quickly to meet rapid changes in load from hour to hour. Exh. TFG-5 at 4. However, responding to such changes in demand can lead to decreased efficiency of the hydropower resource, increased water use and loss of operational flexibility. *Id.* at 6-7. In making such deliveries off-system (such as to CDWR), a hydropower generator has "to charge a price that is related to the forward price of energy to have any degree of certainty that what it is selling today will not cost the operator more to replace tomorrow." *Id.* at 4. This is especially true in a deficit water year such as 2001. *Id.* at 3. As stated by Dr. Tabors:

> The sales price of hydroelectric energy by Powerex in one month needs to be evaluated by reference not to the prevailing price of energy at the time the sale occurred, nor to a theoretical market price

> based on thermal generation and the price of natural gas, but rather to the opportunity cost or value of the energy at any point in the future. The best indicator of this value is the forward market price for electricity. This temporal nature of hydroelectric production must be considered in any refund calculation, if the Commission retroactively determines that overcharges have occurred.
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> *Id.* at 8.

For example, Powerex's witness Mr. Peterson in his direct testimony stated that Powerex relied on the August 2001 forward market price for electricity when it entered into the fixed price arrangement under which CDWR purchased large blocks of power from January 17, 2001 until near the end of the potential refund period. *See* Exh. PWX-6 at 15. Dr. Tabors also testified to the transmission risks confronted by hydropower generators making off-system sales, and observed that in acquiring replacement power in the PNW, hydropower generators faced the same market, climatic and water conditions as other PNW purchasers (and CDWR). Exh. PWX-5 at 6.

It is inappropriate, according to TFG, and contrary to the record evidence in this proceeding, for Mr. Hart to seek to treat these capacity-backed transactions, whereby CDWR was able to draw repeatedly on the generation capabilities of these hydropower systems for large blocks of power to make up for the deficiencies of its own power purchase portfolio and keep its system in balance, as no better than spot transactions. In effect, CDWR found it necessary to rely repeatedly on these other utility systems in order to make up for the generation shortfall that California had managed to create for itself.

Moreover, Mr. Hart has ignored CDWR's own position regarding opportunity costs and the costs of replacement power for hydropower producers in making his overcharge claims, TFG alleges. Incorporated as an item by reference in this proceeding, Exhibit TFG-23 consists of the comments filed by CDWR in Docket No. EL00-95 on March 23, 2001. With respect to the pricing of CDWR's own hydropower production for sales to the ISO, CDWR stated:

> Further, developing the marginal cost of hydrogeneration and the criteria for dispatch by the ISO for such units as imbalance energy is more difficult and *needs to consider the lost opportunity in calling upon such generation at a particular time* by the ISO, *i.e.*, the fuel (water) may not be replaceable once used and there could be a greater value for the generation at a later time.[85]

The only other allegations made by Mr. Hart to support his refund claims were what he referred to as "draconian" payment and credit terms imposed by Powerex. However, the record shows that these terms were fully justified by the "spooky" credit situation surrounding CDWR. Tr. at 859:23-860:3. At the time CDWR began purchasing from Powerex, the ISO and the CalPX owed Powerex some $300 million, which has still not been paid. Exh. PWX-6 at 9. On or about the time CDWR commenced its power purchasing operations for the State of California, Governor Davis commandeered some $1.1 billion in collateral that had been pledged as security to the CalPX, the ISO made its first default to sellers, and

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[85] Comments of the California Department of Water Resources, Docket No. EL00-95-012 (Mar. 23, 2001), TFG-23 at 6 (emphasis added).

the CalPX made its first default to sellers and then went bankrupt. Tr. at 859:5-22. Also, PG&E subsequently filed for bankruptcy in April 2001.

Moreover, TFG argues, during the course of the potential refund period, CDWR's purchases were expressly *not* backed by the full faith and credit of the State of California, and CDWR was existing hand-to-mouth on a series of draws in $500 million increments from the General Fund of California (which have never been repaid), that lasted only as long as a "very few days" in many instances. Tr. at 854:19-21. Additionally, two of the three principal CDWR funding mechanisms prescribed by AB-1X (the CPUC's allocation of a designated portion of the IOUs' retail revenue stream to CDWR's Electric Power Fund, and CDWR's $13 billion bond issue) had not been implemented. Tr. at 851:22-853:13. In view of all these circumstances, and CDWR's refusal to furnish a letter of credit and its inability to obtain the equivalent of a parental guaranty from the State (both of which are common credit assurance devices in the power industry), Tr. at 862:5-863:20, the credit and payment terms imposed on CDWR by Powerex were not draconian, but in fact reasonable, and even generous considering the circumstances.[86]

Apart from Mr. Hart's assertions regarding the high prices paid to Powerex and the credit and payment terms in the Transaction Confirmations between Powerex and CDWR, the California Parties have offered no other evidentiary support for their refund

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[86] The $22.5 million three-day credit limit set by Powerex was sufficient to enable CDWR to purchase 45,000 MWh of power at the fixed $500 per MWh price, and was equivalent to a $225 million monthly credit limit. Tr. at 868:22-869:7; 870:21-25.

claims. Notwithstanding Mr. Hart's personal views on the subject, there is simply *no* probative evidence in the record that would support a finding that the prices paid by CDWR to PNW purchasers during the potential refund period were unjust and unreasonable. By contrast, TFG asserts, both it and its members, such as Powerex, have presented substantial record evidence in this proceeding, including expert testimony, fully justifying the market-based rates charged to CDWR. Thus the Presiding Judge must find that refunds to CDWR for its bilateral purchases from PNW sellers during the potential refund period are neither lawful nor appropriate under Section 206 of the FPA.

TFG avers that the potential refund period in Docket No. EL01-10—December 25, 2000 through June 20, 2001—can never become effective with respect to the California Parties' refund claims. Recognizing the limits on the scope of its authority to order refunds under Section 206, the Commission's July 25 Order specifically directed CDWR to file a complaint if it wished to seek refunds under its bilateral agreements.[87] CDWR has not done so.

CDWR's Deputy Director Mr. Hart stated that he personally favored refunds from Powerex, despite his previous pledge to Mr. Peterson in his capacity as the second highest-ranking official in CDWR that no such refunds would be sought. Exh. CAL-9 at 8; Exh. PWX-6 at 19. Mr. Hart went on to state that he was appearing only as a "fact witness" for the California Parties, and that CDWR's official position is that it is not seeking refunds for these PNW transactions. Tr. at 843:11-844:5. Mr. Hart further indicated that

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[87] 96 FERC at p. 61,515 n. 59.

CDWR intends to do "nothing" about its long-term agreements that are now out of the money (*i.e.*, the contract price is higher than the now-prevailing market price). Tr. at 948:11-12.

Thus, CDWR not only has filed no complaint at the Commission, but CDWR itself has failed to assert any refund claim whatsoever with respect to any of its transactions in the PNW or otherwise. In fact, CDWR has not even intervened in Docket No. EL01-10. Since CDWR is the real California party in interest in these transactions, but has chosen not to participate in Docket No. EL01-10, TFG believes that there is no claim for refunds to CDWR for the Commission to adjudicate, and that the California Parties' direct case is fatally flawed. Under AB-1X, none of the California Parties has the right to review CDWR's purchasing decisions. CDWR's contractual obligations are expressly not obligations of the State of California.[88] The CPUC has found that it has no authority to review the justness and reasonableness of CDWR's purchases. Exh. TFG-16 (CPUC Decision No. 01-03-082 at 14-15 (March 27, 2000)). CDWR, the party with the sole right under AB-1X to determine the justness and reasonableness of its power purchases, has not seen fit to seek refunds or revisit its own purchasing decisions.[89] Under these circumstances, the Commission should not sanction the California Parties' attempts to use Docket No. EL01-

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[88] AB-1X, § 80200(d).

[89] CDWR's failure to intervene has also served to insulate it from discovery during the compressed procedural schedule in Docket No. EL01-10, further aggravating the due process problems discussed above. Should additional proceedings be ordered in this docket, CDWR must be made subject to full discovery, by all parties, regardless of its intervenor status.

10 to accomplish what the California legislature has precluded them from pursuing in California.

If the California Parties are allowed to front CDWR's claims before this Commission, then the July 25 Order's directive that CDWR must file its own Section 206 complaint will have been effectively circumvented. The California Parties should not be allowed to seek a remedy indirectly (retroactive refunds) that the Commission has expressly denied to CDWR – both on the merits and procedurally.

According to TFG, the California Parties have premised their refund claims on generalized and unsupported conclusory statements by their witness Dr. Wolak that sellers exercised market power in California and the PNW. Exh. CAL-5 at 5-6. However, Dr. Wolak did not point to any specific instance where a specific seller exercised market power, nor did he relate his accusation to any particular transaction between CDWR and a counter-party. Similarly, Mr. Hart of CDWR could only make bald and unsupported claims that CDWR had "no choice" in its purchasing decisions. Exh. CAL-9 at 2, 3, and 6.

The Commission in its July 25 Order found the commingling of functions between CDWR and the ISO, to have conferred a competitive advantage on CDWR in negotiating bilateral contracts:

> . . . we note that while DWR is a market participant that competes with other suppliers and purchasers of energy and ancillary services in the ISO markets, unlike other market participants, DWR has had access to the ISO's control room and associated written materials, visual observations and oral statements regarding the ISO's markets, systems, operations and activities. *This has provided*

CDWR a competitive advantage in entering into bilateral contracts.[90]

Based on this finding, TFG now alleges, in Docket No. EL00-95, the Commission determined that there was no equitable basis for granting refunds with respect to CDWR bilateral transactions. This equitable finding was in addition to the Commission's legal determination that "imposing after-the-fact refund liability on California transactions outside the centralized ISO and PX markets is unjustified."[91]

The record in Docket No. EL01-10 shows even more convincing and compelling proof that no equitable basis exists to justify potential refunds to CDWR in this proceeding, for it further documents the problematic relationship between CDWR/CERS and the ISO, which results in CDWR and CERS obtaining preferential access to the ISO's control room and to the ISO's transmission and market information, TFG argues. Even though Mr. Hart was the Director of CERS, he stated that he was unfamiliar with the Commission's standards of conduct for transmission providers, and did not know that they prohibited preferential access to transmission information. Tr. at 821:14-24. Mr. Hart admitted that CERS personnel had a continuing, 24-hour presence in the ISO control room. Tr. at 828:2-22. Mr. Green confirmed that he had met "maybe a half dozen" CDWR or CERS employees "that have transacted on the floor" of the ISO control room. Tr. at 832:15-20. With respect to CDWR's bilateral transactions with PNW sellers, Mr. Green admitted as follows:

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[90] 96 FERC at p. 61,515 (emphasis added).

[91] *Id.*

A: Some of these were done in the day-ahead which was done back at the CERS headquarters, *but the vast majority of it was done real-time.*

Q: From the ISO?

A: From the ISO floor, yes.

Tr. at 831:25-832:4 (emphasis added).

TFG contends that there can be no doubt from these admissions by witnesses Hart and Green that CDWR and CERS had preferential access to the ISO's control room and to the ISO's transmission, operational and market information, in violation of the Commission's standard of conduct requirements. Such access clearly affected "the vast majority" of CDWR's PNW transactions, and without question, conferred a significant competitive advantage on CDWR. Thus, the record in this proceeding provides even more support for the Commission's finding in the July 25 Order that there is no equitable basis for awarding refunds to CDWR when it was competitively advantaged by its preferential access to market and transmission information.

TFG submits, that if the Presiding Judge finds, notwithstanding TFG's arguments to the contrary, that the California Parties' refund claims should be considered in Docket No. EL01-10, then safeguards should be instituted to prevent the California Parties from double-counting these transactions in Docket Nos. EL01-10 and EL00-95. This is necessary to ensure that the California Parties do not have a double-dip refund opportunity. Their claims, if even cognizable, are cognizable only in one proceeding. For purposes of *res judicata* and finality of the Commission decision-making process (not to mention transaction finality in WSCC bilateral markets), these

transactions must be dealt with and disposed of in the California proceeding or the PNW proceeding—but not in both. These claims simply cannot be permitted to cruise the WSCC looking for a landing place.

Additionally, TFG argues that the California Parties' witness Mr. Green laid the predicate for segregation of their claims in his direct testimony and on cross-examination. Mr. Green testified that his testimony and exhibits segregated claims for transactions that should all be certified as part of the PNW for purposes of Docket No. EL01-10. Tr. at 886:23-887:4. He confirmed that anything involving the COB, NOB, Cascade and Summit delivery points was treated as a PNW transaction for purposes of his testimony and refund claims. Tr. at 887:17-21.

Thus the universe of CDWR bilateral transactions which the California Parties claim are subject to refunds in Docket No. EL01-10 is contained in Exhibit Nos. CAL-11 and CAL-12.[92] Mr. Green testified that these transactions he classified as part of the PNW constituted "something less than 50 percent" of CDWR's overall transactions. Tr. at 878:9-17. If the California Parties' refund claims with respect to the transactions identified in Mr. Green's testimony and workpapers are considered in this proceeding, then they should not be considered in any other proceeding, in order to avoid the potential for a double dip.

Bonneville/BPA

Bonneville Power Administration ("Bonneville") avers that Part of the Commission's charge for this proceeding was to develop evidence regarding the

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[92] *See* Exh. CAL-1 at 5-7 (describing CAL-2 and CAL-3); Exh. CAL-10 at 2 (describing CAL-11 and CAL-12, respectively, as revised and corrected versions of CAL-2 and CAL-3).

definition of spot transactions in the PNW. 96 FERC at p. 61,520. The evidence developed through the hearing demonstrates that there is not a uniform or single understanding of what constitutes a spot transaction in the PNW. Rather than having a common definition, spot transactions have a temporal aspect that varies somewhat depending upon whether one is primarily a load serving entity or a marketer. While the evidence may have varied somewhat as to what a spot transaction is, it did not vary as to what is not a spot transaction. Despite the subtle differences between the manner in which a load serving entity and a marketer may view spot transactions, there are clearly some transactions that cannot be considered spot transactions. There is no credible evidence in the record to support the contention that transactions of one month or greater should be considered spot transactions. The refund claimants twist the definition of a spot transaction to the point that a contract of any length could be considered a spot transaction.

The generally inconsistent evidence presented by the Net Purchasers Group (NPG) and California Parties is designed primarily to increase their particular refund claim. Seattle testified that transactions eighteen months or less should be considered spot. Hearing Tr. at 576:22-25. The California Parties and Tacoma, on the other hand, testified that a contract of any length could be considered spot so long as the spot price influenced the contract prices (California Parties) or the transaction involved energy obtained on the spot market (Tacoma). Cal-5 at 4; NPG-46 at 16-17. Tacoma and Northern Wasco's testimony on this point is at best ambiguous. Bonneville asserts that it is not clear whether they are arguing the defi-

nition of spot transactions should include these other types of transactions, or alternatively whether the Commission should expand the scope of transactions under consideration for refunds beyond just spot transactions. The central question to Mr. Movish was:

> Q: What transactions in the PNW *should be considered* in determining whether there may have been unjust and unreasonable charges for spot market sales?
>
> A: The transactions that should be considered are (1) any and all purchases that are 24 hours or less and that are entered into the day of or day prior to delivery; (2) purchases that are either fully, or in part, comprise of energy obtained through spot market purchases; and (3) any purchases that are indexed to spot market prices.

NPG-46 at 16-17 (emphasis added). During his rebuttal testimony Mr. Movish expanded the scope to include any transaction affected by spot market prices. NPG-60 at 2-3. It is important to note that the question does not ask what a spot transactions is, but rather asks what transactions "should be considered" for refunds. This distinction is important because in his answer, Mr. Movish by implication acknowledges that the items 2 and 3 are not "spot transactions," but are transactions for which the Commission should consider for refunds.

Therefore, Bonneville maintains, rather than defining the scope of spot transactions, Mr. Movish is attempting to expand the scope of transactions eligible for refunds beyond spot market transactions. This is squarely at odds with the Commission's July 25th order. In the order the Commission specifically limited the scope of this proceeding to "facilitate the

development of a factual record on whether there may have been unjust and unreasonable prices for *spot market bilateral sales in the Pacific Northwest* . . ." (emphasis added) 96 FERC at p. 61,520. The Commission does not indicate anywhere in the order that this proceeding should be expanded to include anything other than spot market transactions.

Finally, according to Bonneville Tacoma and Northern Wasco also include transactions of any length that have prices tied to an index. NPG-46 at 17. The definitions propounded by those seeking refunds stretches the notion of a spot transaction beyond any standard understood in the industry, according to Bonneville. The temporal nature of a spot transaction no longer exists under these definitions. Under these definitions a transaction of any length could be considered a spot transaction so long as it has tangential relationship to the spot market. These definitions also do not comport with any identifiable class of products traded in markets in the PNW. These inconsistent and expansive definitions suggested by those seeking refunds highlights the rather self-serving nature of the proposed definitions. Rather than being based upon some industry notion of a readily identifiable product the definitions propounded depend in large measure on individual attempts by the group to fit particular contracts within the scope of transactions eligible for refunds in an attempt to maximize the size of the refund claim.

BPA and the TFG presented definitions of spot market transactions that conform to products traded in liquid markets in the PNW, Bonneville argues. While BPA and the TFG propose slightly different definitions, both are consistent with the industry understanding of the term. BPA's definition would

include transactions for the balance of the month or less. BPA-1 at 5-6. The TFG limited the definition to transactions of 24 hours or less made within 24 hours of delivery, with certain exceptions for scheduling procedures. ENR-10 at 6. While these definitions are different, the differences merely highlight the difference between how load-serving entities like BPA and marketers view spot transactions in a slightly different fashion. BPA testified that the distinction between a spot transaction and a term transaction is based on the discretionary nature of the transaction. BPA-1 at 6-7. BPA generally plans its system on a monthly basis, and purchases within the month are viewed as spot transaction because of the limitations BPA has during the month to increase generation or reduce demand. *Id.* Paula Green of Seattle City Light acknowledged during cross examination that Seattle's real-time and next day traders handled balance of month transactions, while all other forward transactions were handled by a different set of traders. Hearing Tr. at 580. This testimony is consistent with the understanding that load serving entities view balance of month transactions in the same category as real time and next day spot transaction. The spot market traders at Seattle City Light deal with transactions that are balance of month or less. *Id.*

The TFG evidence highlights that entities primarily engaged in the business of trading energy view spot transactions on a slightly shorter time frame. This definition fits with the nature of the business, which is not engaged in serving loads but rather in buying and selling energy. The rebuttal testimony of Seabron Adamson contains a survey of traders in the PNW. ENR-25 at 3-4. Those traders surveyed by Mr. Adamson who worked for marketer side of the

business viewed spot transactions consistent with the TGF definition. These traders, consistent with the nature of their business, view spot transactions as 24 hours or less. ENR-29. The survey also contained responses from two traders from NCPA, an entity with load serving obligations on behalf of its members. *Id.* The NCPA traders viewed the balance of the month transactions as spot transactions. *Id.* While both BPA and the TFG present credible evidence of industry definitions of spot market transactions, the NPG and the California Parties have attempted to fabricate definitions of spot market transaction in a effort to maximize their refund claim.

Many of the claimants are seeking refunds for transactions that are not PNW spot transactions, Bonneville contends. As demonstrated by the unrefuted evidence, refunds are being sought for transactions well beyond any reasonable definition a spot transaction, as well as transactions for load service in California. While it is not the charge of this proceeding to find individual refund liability, these claims demonstrate the futility of ordering refunds. Tacoma, Seattle, Northern Wasco and the California Parties are all seeking refunds for transactions longer than a month. Northern Wasco has stretched the definition to the point that they are seeking a refund for a three year indexed contract they have with BPA. BPA-1 at 8-10. While Seattle and Tacoma have a limited number of transactions, which fit under a reasonable definition of a spot market transaction, the majority of their claims involve transactions that are beyond the scope of this proceeding. PWX B1 at 24-25. The objective of these claims does not involve rectifying abnormalities on the spot market,

but rather are attempts to unwind long-term transactions that those claimants now feel were too high.

CDWR/CERS has included in its claim against BPA exchanges with BPA and power sales that BPA sleeved for CRWR/CERS at their request. BPA-1 at 13-16. After the PX declared bankruptcy in January of 2001, BPA entered into several transactions to supply CDWR/CERS with power. BPA-1 at 13. Included among these transactions were exchanges.[93] *Id.* CDWR/CERS and BPA had no mutually negotiated nor agreed upon rates for these transactions. *Id.* at 15. CDWR/CERS took energy from BPA over peak demand hours to avoid extremely low reserve margins or blackouts, and supplied it back to BPA during light load hour periods, when CDWR/CERS could avoid system reliability issues. *Id.* BPA was flexible in working with CDWR/CERS on scheduling their returns to the extent possible to meet their system limitations. *Id.* CDWR/CERS representatives expressed that the return ratios they negotiated with BPA were more cost effective than using their own pumped storage generation alternatives. *Id.* at 15-16. Since there was no dollar/MWh rate established for the exchange transactions, including them would require a separate examination of the "value" to each party as opposed to merely measuring a sales price against a Commission established just and reasonable market-clearing price. The Commission has made clear that the purpose of this proceeding is to develop a factual record regarding spot market bi-

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[93] "Exchanges" are transactions where one party delivers capacity and/or energy to another party, in exchange for a return of capacity and/or energy at a later time, sometimes 24 hours later, sometimes months later. This exchange of capacity and/or energy is in lieu of cash payments.

lateral *sales* in the Pacific Northwest. An exchange is not a sale, a distinction that is made clear in BPA's own organic statutes, which provides the BPA Administrator with express authorization to enter into exchanges, as distinct from power sales. *See* 16 U.S.C. § 832d(b) (Bonneville Project Act).

Finally, Bonneville asserts, CDWR/CERS during March 2001, CDWR/CERS entered into several "sleeve" transactions with BPA under which BPA acted as an agent for CDWR/CERS to purchase the power on their behalf. BPA-1 at 13. "Sleeve" transactions are transactions where a third party (in this case BPA) acts as an intermediary between two other parties. The reasons BPA acted to sleeve some transactions to CDWR/CERS are: (1) CDWR/CERS asked BPA to do so when they were in a start-up mode and had not established themselves in the market; (2) California had been experiencing blackouts, which BPA considered to present a public health and safety issue, with potential to impact broader West Coast reliability; and (3) BPA received minimal compensation to conduct these transactions to cover its transmission expenses, losses, and other transactional costs. *Id.* CDWR/CERS noted in its rebuttal testimony that this description of the context for the sleeving by BPA is correct, and that BPA "offered us energy when no one else would." Cal-10 at 7.

This timeframe was marked by rapidly increasing wholesale electricity prices, volatility in the supply of electricity within California, and a perceived lack of creditworthiness of CDWR/CERS by many Pacific Northwest suppliers. *Id.* at 14. At CDWR/CERS's request, BPA acquired energy in the Pacific Northwest and then resold the same energy to CDWR/CERS. *Id.* This energy was desperately needed by

California in order to maintain reliability margins. Obviously, BPA's willingness to step into the breach on behalf of CDWR/CERS or any other entity will be diminished, if not eliminated, if BPA is ordered by the Commission to refund some portion of the revenues used by BPA to pay for the power provided to CDWR/CERS.

Staff

According to Staff, much of the focus of this proceeding, both in the filed testimony and at the evidentiary hearing, was on the definition of "spot market" as it applied to the PNW. A key characteristic of each definition is the duration of the transactions encompassed by that term. Not unexpectedly, each interest group sponsored a different definition. More surprising than the different definitions sponsored by the groups, however, is the lack of consensus regarding the definition found within a group itself. The TFG, for example, argued that the spot market consisted of transactions of 24 hours or less, for immediate delivery, that were pre-scheduled no more than 24 hours in advance of delivery (with an exception for scheduling over week-ends and holidays). *E.g.*, Ex. AE-1 at 14-15. PacifiCorp and Public Utility District No. 2 of Grant County, Washington (Grant County),[94] however, both of whom are members of the TFG, disagreed with this definition and contended that, in the PNW, the "spot market" included transactions of up to one month's duration (PacifiCorp) or transactions of up to one year's duration (Grant County). In a similar fashion, various

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[94] Grant County was represented jointly with Benton and Grays Harbor Counties. For convenience, we will refer to these public utility districts (PUDs), as "Grant County."

members of the Net Purchasers Group and parties generally aligned with that group argued (in part) that the spot market: (1) included transactions of up to eighteen months; (2) included transactions of up to two years duration and (3) included transactions under contracts of any duration, provided that the price was determined by reference to a spot market index. The position adopted by Commission Staff was that, under the acceptable business practices in the PNW, the spot market included "transactions which are for an hourly, daily, monthly basis and can be up to one year." Ex. S-1 at 17. In sum, there is no shortage of definitions; rather, the issue is selecting the one most strongly supported by the evidence and most appropriate for the region.

Staff submits, that a fundamental starting point in determining a definition of "spot market" in this proceeding is the Commission's orders. Although the Commission has recognized that the West is a single and "inextricably interrelated" market, it has also recognized that it is one characterized by important differences.[95] One such fundamental difference is that, while California administers its spot market sales through a centralized clearinghouse with a single auction price, the other Western states consummate spot market sales through individual bilateral contracts.[96] This essential difference, relied upon by the Commission when it established an evidentiary hearing in this case, was the basis for the Commission's observation that a "'spot market' sale for bilateral transactions in the Pacific Northwest may differ from what is a 'spot market' sale in the California

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[95] June 19 Order at p. 62,545.

[96] *Id.*

ISO and PX organzied spot markets."[97] Commissioner Massey, in his separate dissent and concurrence, noted this statement with approval and went on to add that, in his opinion, a "spot sale in the Pacific Northwest could include sales up to a month's duration or even longer."[98]

Testimony from both the Net Purchasers Group and the TFG show that the PNW differs in many key aspects from the California market, Staff notes. There appears to be no disagreement among the parties, that, as noted by the Commission in its July 25 Order, the two regions have fundamentally different market structures, *i.e.*, California has a centralized clearinghouse to administer spot market sales, while the PNW does not. Thus, rather than having a single trading point for all spot transactions, the PNW has multiple trading points and trades may take place at any point that the trading partners choose.[99]

The parties also agree, Staff maintains, that a second salient characteristic of the energy market in the PNW is the fact that its primary fuel is water. Unlike California, which has a preponderance of fossil fueled generation, the PNW obtains approximately 60 percent of its energy from hydropower. *E.g.*, Exs. NPG-4 at 24; S-1 at 8; AE-1 at 3; ENR-1 at 8. Mr. Robert McCullough, a witness for the Net Purchasers Group, testified that, "[f]or many years

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[97] July 25 Order at p. 61,520 and note 74.

[98] *Id.* at p. 61,522.

[99] These trading points include the California-Oregon border (COB), the Nevada-Oregon border (NOB), Palo Verde and Mid-Columbia. At the very least, a "modest price differential" exists among these points. Ex. NPG-74 at 7; Ex. PWX-1 at 20; Ex. BPA-1 at 6.

FERC has recognized that the PNW and other primarily hydroelectric systems operate very differently from thermal systems like those in California." Ex. NPG-1 at 6. One consequence of this difference is that, since hydroelectric projects are incapable of running constantly, Northwest utilities make purchases from thermal units "on an hourly, daily, weekly or monthly basis" to fill in when their hydroelectric project are incapable of serving load. *Id.* at 7.

Staff states that Mr. Samuel Van Vactor, a principal witness for the TFG, characterized the PNW Market as "radically different" from that of California. Ex. ENR-1 at 3. He offered detailed testimony concerning the differences between the PNW and the California Markets. To quote Mr. Van Vactor's summary concerning these differences (*id.* at 9):

> The Pacific Northwest market has been in operation for over twenty years and has not undergone a radical restructuring; there are no substantial 'stranded costs' in the region; the major trading entity in the region is a federal agency; the region is dominated by hydroelectricity generation and relies less on spot trading; the transmission infrastructure in the major population areas is relatively uncongested; demand is more price sensitive than in California; utilities were free to choose how and when to trade [and] there was no mandate to trade in a centralized market or exchange. . . .[100]

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[100] Mr Van Vactor completed his summary by noting that "utilities in the region were forewarned about the risk of depending on the spot market to meet firm load." The Net Purchasers Group, however, generally maintained that its members had taken all appropriate measures to lessen their dependence on the spot market. *E.g.*, Ex. NPG-4 at 18-21.

Mr. Van Vactor explained that the Northwest's limited ability to store water (the region's reservoirs can store approximately three months worth) allows it "some flexibility in the use of thermal resources." *Id.* at 11. A resulting characteristic of the region's markets, according to Mr. Van Vactor, is that it has "a greater number of forward contracts" than does California. *Id.*

Additionally, Staff contends, as noted in the Commission's July 25 Order (96 FERC at p. 61,520), and established by the evidence here, energy transactions in the PNW occur as a result of bilateral contracts negotiated by the parties thereto. Because the PNW has no mandatory clearinghouse comparable to the CAISO, there is no single uniform set of terms and conditions that apply to all power transactions. Ex. NPG-74 at 6. Instead, wholesale power in the Northwest is bought and sold under circumstances specific to each buyer and seller. *Id.* Mr. Robert McCullough testified that in the PNW "[r]elatively few transactions take place on an hourly basis" due to the operating realities of the electric system, *i.e.*, "[f]ew control areas can wait until the hour of operation to arrange for supply." Ex. NPG-1 at 9. (Mr Adamson, for the TFG, agreed that the PNW has a relatively small real-time market. Ex. ENR-10 at 8.) Thus, the majority of the "players" purchase power on a forward basis, usually on a daily, weekly or monthly basis. Ex. NPG-74 at 9.

Staff submits that the evidence establishes that the majority of the bilateral contracts in the PNW are either schedules under the Western Systems Power Pool Agreement (WSPP) or contracts with the Bon-

neville Power Administration (BPA).[101] Exs. S-1 at 8; NPG-4 at 13; NPG-74 at 6; GT-1 at 13; ENR-1 at 3. The WSPP Agreement is an "umbrella agreement" that establishes standarized terms for discretionary power transactions among WSPP members. Ex. NPG-74 at 4; NPG-4 at 13. Typically, potential counterparties in a WSPP agreement use oral or written confirmations to establish the terms of a particular sale transaction, such as its volume, price and duration; there may be several confirmations during the term of the contract.[102] NPG-74 at 6. The WSPP Agreement does not define spot market.[103] Ex. S-1 at 12. BPA's website, although similarly failing to define spot market, does state that a spot market price "often" occurs as a result of an hourly or weekly transaction. Ex. S-1 at 13.

According to Staff, the evidence shows that many of the market participants in the PNW fall into one of two categories: they are either power marketers or

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[101] A preliminary examination of the data submitted to the Presiding Judge and to Staff on August 16, 2001, however, indicates that a significant number of contracts do not fall under either category. There are other types of bilateral arrangements and contracts under FERC tariffs. Ex. S-3 at 7.

[102] As one witness explained, the WSPP "agreement provides for some standards, but the specifics of any single deal, be it a day-ahead, real-time, or quarterly transactions, are contained in the confirmation that goes along with the deal." Ex. GT-1 at 6.

[103] It does state that all transactions under the Agreement and Confirmation Agreements "are forward contracts, *as those terms are used in the United States Bankruptcy Code*." Ex. S-1 at 12 (quoting § 35 of the WSPP agreement; emphasis added). The clear wording of the Agreement, in Staff's view, limits its characterization of these arrangements as "forward contracts" to their use in bankruptcy proceedings.

Load Serving Entities (LSEs). These two groups are characterized by important differences. LSEs, for example, "typically" own their own generation resources, which they use to serve their load obligations, *i.e.*, retail customers, end users and wholesale requirements customers. Ex. AE-1 at 5. Because the production of hydroelectricity depends on water levels, an LSE's native generating facilities will sometimes be more than enough to serve its load obligations and will sometime be less. *Id.* When it is less, the LSE generally obtains needed supply through contracts with third parties; when it is more, the LSE typically sells the surplus to others. *Id.* Unlike an energy marketer, an LSE has a legal obligation to provide service, regardless of the level of demand and of the cost of the energy; they are not free to abandon native load. Ex. NPG-4 at 16. Accordingly, a Northwest LSE must purchase several days to many months in advance.[104] *Id.* at 17.

A marketer, unlike an LSE, does not own generation, but buys and sells electricity from a portfolio of assets. Ex. AE-1 at 13-14. These portfolios contain power products, or contracts, with differing terms, degrees of risk, delivery points and prices. Marketers typically purchase rights to energy and capacity from sellers, which, in turn, they offer to buyers on a continuous basis. *Id.* Marketers have no obligation to serve load and no continuing obligation to the parties who use their services.

Staff avers, that the parties in this case, as previously noted, offer several definitions of spot market

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[104] The record contains abundant evidence that prudent utility practice, as well as FERC policy, discourages over-reliance upon spot purchases. Exs. NPG-74 at 5; PacifiCorp 1 at 5; PWX-1 at 21.

transactions. Staff discusses the main evidentiary underpinnings of these differing definitions below.

According to Staff, Mr. Stephen Oliver testified on behalf of BPA, which owns and operates approximately 80% of the PNW's high-voltage transmission systems and markets 40% of the electricity consumed in the region. Ex. BPA-1 at 3. It is thus a dominant presence in the region's power markets. Exs. ENR-1 at 10; BPA-1 at 3. Mr. Oliver explained that the Northwest and California markets were "structurally different." Unlike California, which has a single trading point for all spot transactions, the PNW has a number of points of interconnection at which transactions occur on a bilateral basis. In addition, Mr. Oliver pointed out that "the time period of the transactions" in the Northwest "is not as structured as in the ISO and PX." *Id.* at 6. Based on these structural differences, Mr. Oliver testified (*id.* at 5) that

> Pacific Northwest spot market bilateral sales should be limited to real-time sales (within the same day, next hour), pre-scheduled sales (for the following 24-hour period), and within month and balance of the month sales (those sales that occur after the first of any month, for some short duration within the month, or for the remainder of the month) executed during the period December 25, 2000 through June 20, 2001, with delivery points inside the Pacific Northwest, including deliveries at the California-Oregon and Nevada-Oregon borders (COB and NOB) to serve loads within the Pacific Northwest.[105]

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[105] Mr. Oliver excluded bilateral transaction to serve load outside the Northwest from his definition because he considered

Observing that spot transactions "by their nature" are purchased to balance the short-term needs of the underlying loads, Mr. Oliver explained that within the month and balance of the month transactions were appropriately included in his definition because they were "usually made because of unanticipated changes in loads or generation after the month begins" and (like spot sales) were typically not discretionary. *Id.* at 6.

Mr. Stan Watters, an officer of PacifiCorp whose responsibilities included the oversight of his company's wholesale sales and trading functions, offered significant testimony on the spot market issue. Ex. PacifiCorp-1. PacifiCorp, as explained previously, is a member of the TFG and generally "supports and adopts as its own the testimony sponsored by" the Group's witnesses; in particular, it agrees with the Group's "central position" that ordering refunds among the PNW Parties is "wholly inappropriate." *Id.* at 2. Nevertheless, Mr. Watters appeared to rebut the Group's testimony that spot market was limited to 24 hours or less. *Id.* Mr. Watters' testimony is particularly instructive because it explains the business practices of LSEs in the PNW and why a "24 hour or less" spot market definition is inappropriate for that region.

Consistent with testimony offered by the Net Purchaser Group (*e.g.*, Ex. NPG-4 at 17), Mr. Watters stated that LSEs attempt, to the "maximum extent practicable," to avoid exposure to "the high volatility of the near-term market." *Id.* at 3. Because long-term planning decisions are "inevitably imperfect,"

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such an exclusion a "practical" way to prevent overlap with the California complaint proceeding. Ex. BPA-1 at 7.

however, LSEs are forced to engage in "a process of buying and selling power in transactions up to one month in duration" in order "to triangulate toward a precise balance of loads and resources when the hour of actual delivery occurs." *Id.* These one month purchases frequently require an LSE to engage in near-term sales. As Mr. Watters explained, LSEs frequently buy "standard products" offered by the industry to meet demand during their heavy load hour because doing so minimizes their exposure to the unpredictable hourly market. Despite the fact that it is the most-economical and lowest-risk means for meeting peak load demands, however, a standard product may deliver more power than the LSE needs. For this reason, and because expected load sometimes fails to materialize, an LSE is forced to sell the surplus energy into the "near-term market." *Id.* at 3-4. As Mr. Watters went on to explain, transactions up to one month in duration, as well as one-hour purchases or sales made on a particular day were equally "integral to the load balancing function of load-serving entities and . . . substantially affected by whatever imperfections might have existed in near-term markets;" he knew of "no principled basis for distinguishing" between the two. *Id.* at 4-5. Mr. Watters testified that a "24 hour definition" penalized prudent utilities that had followed "Commission policy and prudent utility practice" by reducing their exposure to the volatile hourly and daily market. He further testified that defining "spot" to include monthly transactions not only avoids this "inequitable and perverse" outcome but also establishes "a defensible boundary between [an LSE's] 'planning' function and [its] near-term load balancing function." *Id.* at 5.

Ms. Natalie Tingle-Stewart, an expert analyst with the Commission's Trial Staff, testified that her "preliminary conclusion," based on the transactions that she had been able to examine in the limited time available, was that spot transactions in the PNW "should be transactions which are for an hourly, daily, monthly basis and can be up to one year." Ex. S-1 at 17. She based her conclusion, she explained, on business practices in the PNW and the "peculiarities" of the market in that region. *Id.* at 17; Tr. 1240. At the hearing, Ms. Tingle-Stewart testified that she had considered the fact that many localities "typically" defined "spot" as transactions of 24 hours or less, as well as the distinction between spot and forward transactions. Tr. 1240. In view of the differences in the Northwest markets, however, these factors had not affected her preliminary conclusion. Tr. 1240-41.

Ms. Tingle-Stewart explained that she had researched the definition of spot market used by several entities that were either councils or regulatory agencies operating in the PNW or that traded with, or were bordered by, the Northwest's energy market. Ex. S-1 at 12. Her examination indicated that there was no consensus regarding the definition. *Id.* at 11-15. Ms. Tingle-Stewart also reviewed and considered the various spot market definitions found in the testimony and exhibits filed by EWEB, SMUD, the Net Purchasers Group and the California Parties. On cross examination, Ms. Tingle-Stewart stated that, after filing her written testimony, she had also reviewed responsive testimony filed by the TFG.[106]

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[106] These exhibits and testimony, which were filed by the group on the same date as Staff filed its responsive case, had

She testified, however, that her review of the TFG's evidence had not affected her preliminary conclusion, *i.e.*, that spot transactions could be up to one year's duration. Tr. 1241.

Several witnesses from the Net Purchaser Group and the California parties testified, among other things, regarding an appropriate "spot" definition. These include Ms. Paula Green (an employee of Seattle City Light), Mr. Robert McCullough (a consultant), Mr. Scott Spettle (an employee of EWEB) and Mr. Philip Movish (a consultant).

Ms. Paula Green testified that for LSEs "the standard practice for spot market transactions outside of California includes monthly forward purchases and sales." Ex. TFG-4 at 18. Pointing to significant price increases in the spot market, beginning in May 2000 and a deteriorating water supply that affected the availability of hydropower, Ms. Green testified that Seattle City Light "decided it would be prudent to make significant forward purchases in the monthly spot market to serve load." *Id.* at 12-15. In Ms. Green's opinion, the PNW's spot market included "any transaction up to 18 months in duration." *Id.* at 23. She based her opinion on the fact that the City of Seattle had delegated authority to the utility to enter into short-term spot-market agreements for storage, sales and purchases.[107] Ms. Green further testified

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been unavailable to Ms. Tingle-Stewart when she prepared her written testimony.

[107] Ms. Green explained that the 18 month period was based on "standard practices" associated with the Pacific Northwest Coordination Agreement, which was established in 1962 by all the major utilities operating control areas in the Northwest. Ex. NPG-4 at 23. The Coordination Agreement establishes monthly obligations for the signatory parties based on a "water

that she would limit spot market transactions to 18 months because anything longer was "inconsistent with the operation of the hydroelectric system in the Northwest." *Id.* at 24.

Mr. Robert McCullough testified that, in the PNW, all "purchases and sales of less than one year duration" are regarded as "spot purchases." Ex. NPG-1 at 12. Consistent with Mr. Watters' testimony regarding the region's use of "standard products" to supply buyers' needs, Mr. McCullough testified that sellers package hourly supplies into "daily, weekly, or monthly blocks" because these packages are more efficient for both buyers and sellers than "new negotiation[s] for every hour." *Id.* at 9. As a consequence, spot purchases in the PNW "tend to reflect the longer operational needs of the ultimate consumers." *Id.*

Like Ms. Green and Mr. McCullough, Mr. Scott Spettel, the witness for EWEB, testified that spot transactions were considerably longer than 24 hours. Ex. NPG-74. Mr. Spettel stated that wholesale power in the region was commonly "bought and sold for terms ranging from next-hour, next day, balance of month, monthly, and quarterly through a term of twelve months." *Id.* at 6. Mr. Spettel testified that, in his opinion, each of these transactions was part of the "spot market." *Id.* at 7. Noting that transactions of a month or longer are frequently referred to as "term" or "mid-term", Mr. Spettel stated that "the pricing of these transaction is related to the price volatility observed or expected in the next-hour and next-day markets." *Id.* Mr. Tim Culbertson, the

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year." The City of Seattle recognized that spot transactions "would be related to the Coordinated system plan and regulation" and could extend beyond a current fiscal year; hence, the 18 month delegation. *Id.* at 24.

witness for Grant County,[108] agreed "for the most part" with Mr. Spettel's testimony. Ex. GT-1 at 6. Mr. Culbertson testified that an appropriate definition of spot market should include transactions that were longer than real-time and day-ahead because "monthly, quarterly, and even transactions up to a year involve a standardized product, can be consummated just as fast as a day-ahead or real-time deal, and trade at prices that are, for the most part, transparent." *Id.*

Mr. Philip Movish, a witness for the City of Tacoma, Port of Seattle and Northern Wasco, testified that spot transactions included: (1) all transactions of 24 hours or less, entered into the day of, or day prior to delivery; (2) purchases that partially or entirely comprised "energy obtained through spot market purchases;" and (3) "any purchases that are indexed to spot market prices," regardless of the duration of the underlying contract. Ex. NPG-33 at 17. He acknowledged that, for California, the Commission had defined spot sales "as sales that are 24 hours or less and that are entered into the day of or the day prior to delivery." *Id.* at 16. He stated, however, that the definition should be adjusted to account for the differences in the Northwest market. *Id.*

Dr. Frank Wolak testified for the California Parties. Noting that Northwest LSEs generally turned to the market only when their own generation resources were insufficient to serve load, he testified that their need "for additional energy is rarely for a single hour or for a single day;" their needs, rather rather,

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[108] Grant County and its associated PUDs, although members of the TFG, did not agree with that Group's definition of spot market.

extend over "hours, days or even months." Ex. Cal-5 at 4. Dr. Wolak stated that the LSEs' "need for additional energy is typically for a significant period of time because the Pacific Northwest is a hydro-based system." *Id.* He explained that, because water conditions usually last for an entire year, and the impact of a low water year is felt the following year, LSEs must replenish their reservoirs over a long period of time. Based on this factor, as well as his analysis of a generator's potential exercise of market power, he concluded that "bilateral sale[s] of electricity in the Pacific Northwest market should be subject to refund . . . as long as two years in advance of the delivery date. *Id.* at 5.

The TFG (except for PacifiCorp and Grant County) argues that spot transactions in the PNW are "sales with a duration of 24 hours or less," entered into the day of, or the day before delivery, except when the latter occurs on or after a weekend, holiday or WSCC scheduler conference." Tr. 1110-11; *e.g.*, Ex. ENR-10 at 8. TFG's principal witnesses on this issue were Samuel Van Vactor (Ex. ENR-1); Seabron Adamson (Ex. ENR-10); Dr. Richard Tabors (Ex. PWX-1) and Mr. Christopher Stelzer (Ex. AE-1). These witnesses prepared their testimony in conjunction with each other and with Mr. Scott Jones (Ex. PPL-1); the five testified as a panel at the hearing. Ex. PPL-1 at 2; Tr. 1061. Mr. Stelzer is employed as an energy trader for Avista Energy, Inc. (a member of the TFG), while Dr. Tabors and Messrs. Van Vactor, Adamson and Jones are consultants retained as witnesses by various members of the TFG. Exs. AE-1 at 1; ENR-1 at 1; ENR-10 at 2; PWX-1 at 2; PPL-1 at 1.

Mr Adamson testified that a "standard economic definition" of spot market was limited to "transac-

tions for immediate delivery, at prevailing prices." ENR-10 at 6. He modified this definition, however, to that quoted above, to be "consistent with actual trading practice" in the PNW. *Id.* at 8-9. Mr. Adamson explained that his modified definition was "appropriate" because it "capture[d] the immediate nature of spot transactions;" it "recognize[d] the realities of the Pacific Northwest market" and it could be consistently applied. *Id.* at 8.

Although acknowledging that "immediacy" was a component of the economic definition of spot transactions, Mr. Adamson explained that it was necessary to "balance strict economic interpretations" with market realities. *Id.* at 9. His definition allowed an exception to immediate delivery for scheduling conventions, he explained, because limiting the term to "transactions . . . strictly made within 24 hours of delivery would not be consistent with actual trading practice." *Id.* at 8-9. He had also extended the "standard" definition to include transactions that were extended beyond "real time" because "the market d[id] not operate that way." *Id.* at 9.

At hearing, Mr. Adamson clarified that his "judgment about the appropriate definition of the spot market really had two components, an economic one and a practical one." Tr. 1112. With respect to the latter, he relied upon a telephone survey of four energy traders, as well as "a kind of e-mail survey" of twenty-six respondents. On cross examination, Mr. Adamson testified that he had not included individuals from BPA or PacifiCorp (the two largest participants in the market) in his survey. *Id.* He also conceded that the twenty-six respondents in his e-mail survey were employed by members of the TFG and

that one, Mr. Christopher Stelzer, was a fellow panelist. Tr. 1144-49.

Dr. Tabors largely agreed with Mr. Adamson. He believed that the Net Purchasers Group was trying to obtain refunds for "forward," rather than "spot," transactions. Ex. PWX-1 at 21-22.

Mr. Van Vactor defined "spot" transactions as those made "for immediate delivery of the product," with "[t]ypically" no ongoing commitment between buyer and seller. Ex. ENR-1 at 8. He stated that electricity "is different from other commodities in that a physical transfer does not take place in the usual fashion;" according to Mr. Van Vactor, the significant factor for determining spot transactions for electricity was the scheduling of generating units for dispatch. *Id.* On cross examination, he testified that his definition of spot markets and those of his fellow panelists, were "based on our experience" in markets and regions other than the Pacific Northwest." Tr. 1116.

The last panelist, and the only one with actual experience in trading energy, was Mr. Christopher Stelzer, a trader employed by Avista Energy, a marketing and trading company that does not own any generating assets. Ex. AE-1 at 2. Stating that he agreed with Mr. Adamson's definition of spot market, Mr. Stelzer testified that the definition was consistent with his experience as an energy trader. *Id.* at 14. At the hearing, Mr. Stelzer answered a number of questions on cross examination regarding "standard products," which Mr. Stelzer defined as the "products that are most commonly traded in the market and don't need further changes in terms of normal WSPP agreement." Tr. 1127-28. One such "standard product" is a "6 X 16 peak product," de-

signed for heavy load periods, which delivers energy six days a week (Monday through Saturday) for sixteen hours a day (6 a.m. to 10 p.m.). Tr. 1130. Mr. Stelzer testified that LSEs had "a need to deal in things other than standard products in order to cause loads and resources to balance." Tr. 1137-38. Marketers by contrast are able to meet their obligations simply by purchasing standard products. *Id.*

Staff maintains, that Mr. Van Vactor's testimony also raised doubt about the degree to which the advocates of a 24-hour definition based their opinions on the actual conditions prevalent in the PNW market. He stated that his opinions and those of his fellow panelists were based on their experience in markets other than the PNW. Tr. 1116. Given the Commission's express recognition that the PNW spot market may not be identical to that in California, this statement undermines the value of Mr. Van Vactor's testimony, as well as that of his fellow panel members.

In summary, it is Staff's position that the spot market in the PNW region should be defined to include transactions that are greater than 24 hours. This reflects much more accurately the nature of the PNW market, where LSEs must balance short-term purchases, which include not only 24-hour purchases but also ones of longer duration, often for a week or balance of the month, to meet power needs not satisfied by their largely hydro generation capabilities. In contrast, the witnesses advocating a 24-hour definition, such as Mr. Adamson, expressly recognized that a "standard definition" must be modified to fit the business realities of the PNW. Yet these witnesses went on to base their views more on an academic, definition-driven generalized notion of what a spot market should be than on actual conditions and

business practice in the PNW market. For this reason, their testimony is less probative.

Just as Staff does not agree with the TFG's "24 hour or less" position,[109] however, it also takes issue with the contention of the Net Purchasers that "spot" transaction necessarily include all those transaction that range up to 18 to 24 months or "any purchases that are indexed to sport market prices," regardless of the duration of the underlying contract. Exs. NPG-33 at 17; NPG-1 at 9; NPG-4 at 23. Although Staff found the TFG's evidence concerning the appropriate "spot" definition less than compelling, it agrees with TFG's contention that any useful definition of "spot" must be geared towards some sense of immediacy, as understood in the market of a particular region. *See* Ex. ENR-10 at 8. Staff also agrees with both BPA and Pacificorp that decisions made as part of an entity's "planning function do not properly belong in a proceeding that is limited to spot market transactions." Exs. BPA-1 at 6; PacifiCorp-1 at

Based on Staff's preliminary examination of the massive data submissions in this case, it concluded that the spot transactions could range up to one year. Should the Commission decide to continue this proceeding for a determination of individual refund claims, a more precise definition would be needed. Based on the entire evidence in this proceeding, including the hearing, Staff now believes that the most appropriate limitation for spot market sales in the PNW is one month. Staff, however, is also of the opinion that parties should be permitted to show

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[109] We are using this term as a short hand reference to the definition of "spot market" sponsored by the TFG. *See, e.g.*, Ex. ENR-10 at 8.

specifically, for transactions longer than one month but not more than one year, that particular contracts were not part of long term planning and thus should be considered spot transactions. Defining spot market as including transactions that extend up to one month is consistent (as explained previously) with the realities of the market in the PNW and includes transactions that "are of short enough duration that there are usually no other reasonable alternatives than to purchase from the market, or sometimes to sell, as in the case of non-discretionary generation production, such as may occur with hydroelectric systems." Ex. BPA-1 at 6-7. Limiting spot transactions to one month also serves to exclude transactions that are part of an entity's "planning" function; we agree with PacifiCorp and BPA that these transactions do not belong in a proceeding limited to spot sales. *See* Ex. PacifiCorp-1 at 3; Ex. BPA-1 at 6.

Staff also noted, that although the record in this proceeding did not establish that any one entity exercised market power, there is evidence that, if further investigated, may establish that market power was exercised, Staff states. Staff asserts that if it is established that a party exercising market power also sold under long term contracts with prices indexed to the spot market, such transactions (although not spot sales) should also be subject to refund.

The Presiding Judge's August 23 Order On Issues stated that the spot market issue pertained to "the Pacific Northwest as defined in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 893a(14)" (Conservation Act). This statement incorporated the stipulation of the parties regarding this issue.

In examining the evidence regarding spot market, Staff noticed that, notwithstanding the parties' stipulation, certain witnesses maintained that the geographic definition of PNW found in the Conservation Act was, or was not, appropriate for use here.[110] If the Commission determines that further proceedings are warranted, it is Staff's view that it should decide (1) whether the geographical definition of PNW is settled by the stipulation; and (2) if not, whether the Conservation Act's geographic definition should be used in any refund proceeding.

Recommendations

I agree with Staff that the Commission has recognized that the California and PNW power markets, while "inextricably interrelated," also differ in important ways. In particular, California has a centralized spot market with a single auction price, while the PNW spot market operates through individually negotiated, bilateral contracts. California also relies far less on hydropower than does the Northwest. These fundamental differences support a the conclusion that the spot markets in the two regions may be defined in a different manner. This comports with the Commission's determination that, while the Western Region is one market, it is a market characterized by significant differences.[111] In view of the Commission's statement in this case, that the spot market in the Northwest may differ from that in California, I believe that the most probative evidence is evidence that focuses most directly on the differences between the two regions and how (if at all)

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[110] *See, e.g.*, Exs. ENR-1 at 2-7; Ex. NPG-12 at 2-6; PWX-7a at 5.

[111] June 19 Order at p. 62,545.

those differences bear on the operation of each region's spot market.

I further agree with Staff that the manner in which LSEs in the PNW market purchase power indicates that spot market purchases are considerably more variable in duration than in the California market and thus cannot practically be encompassed by a 24-hour limitation. Due to the fact that electric generation is primarily dependent on water in the PNW, as opposed to fossil fuels as in California (*e.g.*, Ex. ENR-1 at 8), the energy supply is subject to greater variation due to changes in natural conditions. Ex. AE-1 at 5. Water conditions usually last for a year, and the impact of a low water year is felt the following year. Thus, when the LSEs need energy, it is rarely for a single day, but instead for significant periods of time. Ex. Cal-5 at 4.

Furthermore, the LSEs have a legal obligation to provide service, regardless of the level of demand. Ex. NPG-4 at 16. They therefore cannot afford to "wait until the hour of operation to arrange for supply." Ex. NPG-1 at 9. They instead must purchase days or months in advance. Ex. NPG-4 at 17. As Mr. Watters explained, to avoid the volatility of the near-term market, LSEs engage in a process of buying power in transactions up to one month in duration in order to "triangulate toward a precise balance of loads and resources when the hour of actual delivery occurs." Ex. PacifiCorp at 3. Within-month and balance-of-month transactions are undertaken for the same purpose as 24-hour transactions—the need to make up for unanticipated changes in loads or resources—and, like the shorter transactions, the longer ones are not discretionary. Ex. BPA-1 at 6. Transactions of various lengths are thus part of

the same cohesive process; as testified by Messrs. Watters and Oliver, these transactions are properly part of the PNW spot market. To separate those transactions into categories, such as "more than 24 hours" and "less than 24 hours," would be to ignore arbitrarily the purpose for which the transactions are carried out. As Mr. Watters stated, there is "no principled basis for distinguishing" between the two. Ex. PacifiCorp at 4-5.

Other testimony showed that actual practices in the PNW compel the conclusion that the spot market there is considerably broader than 24-hour transactions. I agree with Bonneville that the testimony favoring a 24-hour definition, by contrast, reflects more the practices of the marketers in the region or those who are not LSEs. Mr. Adamson, for example, based his opinion in part on an e-mail survey of 26 respondents, who mostly represented the views of marketers rather than LSEs. Two respondents which were LSEs supported Bonneville's definition. As explained above, marketers are impacted less by the realities of the PNW market than are LSEs. The former do not own generation and are under no legal obligation to provide power to anybody. Ex. AE-1 at 13-14. They therefore do not operate under the same need to integrate longer and shorter term purchases so as to balance their supply and demand.

In this regard, I find Bonneville's testimony persuasive and the preponderance of the evidence makes me recommended that Bonneville's definition for spot markets be adopted. To wit, real-time, prescheduled, and within the month and balance of the month transactions during the relevant time period at issue in this proceeding. I find persuasive that within the month or balance of the month transactions, to

balance loads, should be included in the definition of spot markets in the Pacific Northwest. Moreover, I agree with Staff as explained in its brief and TFG that longer transactions including transactions indexed to spot market prices, should not be included in the definition. I agree that the definition should include some sense of immediacy, as understood in the market of a particular region. In so doing I am aware that the Commission in previous decisions encompassing the area at issue in this proceeding, has referred to spot market transactions as ". . . . means sales that are 24 hours or less and that are entered into the day of or day prior to delivery." *See* June 19 order. I believe within month and balance of month transactions, to balance load, based on the evidence in this case is an appropriate definition for spot market sales in the Pacific Northwest.

I agree with Bonneville that both exchanges and sleeve transactions should not be part of this proceeding and therefore, so recommend. These transactions are not spot market transaction within the meaning of the definition.

I believe the record supports the definition of Pacific Northwest used at the hearing as stipulated to by the parties or as defined in the Pacific Northwest Electric Power Planning and Conservation Act ("Conservation Act"). I agree with TFG that the definition informs and guides the conduct of market participants. Moreover, this is the definition used by Puget in its complaint. The definition matches the operational characteristics of the power systems and waterways and conforms to the existing political organization of the region. The parties arguing for a different definition in the post-hearing briefs have not given compelling reasons for me to reach a differ-

ent conclusion. I find significant Mr. Van Vector's testimony that all refund proponents except for California, are within the Conservation Act territory, and thus, adopting a broader definition, would expand the investigation of this preliminary hearing. It also bears noting that the Commission, when it has deemed it appropriate has used the WSCC as the geographical boundary. *See e.g.* June 19 Order at n.4. I recommend adoption of the definition of the Conservation Act.

Additionally, I find that Staff's assertion that there is evidence that if further investigated may establish that market power was exercised is of very little probative value. Staff did not submit any testimony on the issue of market power. Moreover, in light of the record developed in this proceeding, I recommend that this statement not be given any weight. Furthermore, as discussed under issued number two below, the evidence developed in this case, does not support Staff's speculation. The discussion below, further supports this recommendation.

Although I allowed the California Parties to participate in this proceeding, in light of the record developed in this case, I recommend that the claims dealing with CDWR/CERS bilateral transactions, not be considered in this record. The transactions do not involve transactions into the Pacific Northwest and Puget's complaint specifically referred to transactions into the Pacific Northwest. To wit, the complaint requested an order "capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy or capacity under the Western System Power Pool Agreement ("WSPP Agreement"), may sell capacity or energy into the Pacific Northwest wholesale power markets." There-

fore, EL01-10 does not include bilateral transactions involving CDWR since the transactions were sales into California. Moreover, the Commission declined to order refunds with respect to these same agreements in the California refunds proceeding or Docket EL00-95.

The claims by the California Parties were fully addressed in the July 25 Order, in Docket EL00-95. It bears noting that in the July 25 Order the Commission stated:

> We believe imposing after-the-fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding when the Commission consistently encouraged California load serving entities to acquire a balanced portfolio of short, medium and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000, through June 20, 2001 to include transactions outside the ISO and PX centralized markets would simply hinder the ability of parties to enter into new bilateral contracts. . . . . In addition, by voluntarily entering into bilateral transactions outside the ISO and PX, DWR made a conscious decision to forego the refund protection that the Commission provided for purchases through the ISO and PX. Thus, there is no equitable rationale that supports making DWR's bilateral contracts subject to refund.
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> *July 25 Order*, *slip op.* at 32-33.

The Commission's previous decision concerning the CDWR claims is applicable to this case. I agree with TFG that the correct construction of EL01-10, is to exclude CDWR bilateral transactions and is limited

to transactions within the scope of Puget's complaint.[112]

2. May unjust and unreasonable prices have been charged for spot market bilateral sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

NPG

The Attorney General of Washington filed a brief in support of refunds arguing that refunds are in the public interest because the rates were unjust and unreasonable.

NPG avers that in its July 25 Order, the Commission states that this "preliminary evidentiary proceeding" is "intended to facilitate development of a factual record on "whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest."[113] The August 23, 2001 "Order on Issues" lists whether or not unjust and unreasonable prices "may" have been charged for Pacific Northwest spot market sales during the period December 25, 2000 through June 20, 2001, as an issue in this proceeding. NPG maintains that the Commission has already determined that

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[112] If the Commission finds that the claims should be considered, the other issues alleged by TFG, (that the transactions involved are not spot market, standing, access to ISO), Duke Energy (the California parties failed to meet their burden of proof because their underlying data is erroneous) must be considered. I agree with Staff the Section 35 of the WSPP Agreement states that all transactions under the Agreement and confirmation agreements are "forward contracts, as those terms are used in the United States Bankruptcy Code." Exh. S-1 at 12. This limits the characterization of forward contracts to their use in bankruptcy proceedings.

[113] July 25 Order, 96 FERC at p. 61,520.

unjust and unreasonable prices were charged for Pacific Northwest spot market sales during the refund period. Moreover, despite the truncated nature of this preliminary evidentiary hearing, the record compiled in this proceeding confirms the Commission's finding that Pacific Northwest spot market prices during the refund period were unjust and unreasonable.

Section 206 of the Federal Power Act ("FPA") empowers the Commission, "upon a complaint" or "its own motion," to institute an investigation into whether existing rates or charges collected by any public utility for any jurisdictional sale are "unjust, unreasonable, unduly discriminatory or preferential."[114] Section 206 requires that, upon finding that existing rates are unjust and unreasonable, the Commission "shall determine the just and reasonable rate . . . to be thereafter observed and in force . . . ."[115] The Commission has held that, under Section 206 of the FPA, it has the "responsibility" to fix the just and reasonable rates for jurisdictional sales of power.[116]

In its November 1 Order, the Commission found "that the existing [California power] market structure and market rules, in conjunction with an imbalance of supply and demand in California, have caused and, until remedied, will continue to have the potential to cause, unjust and unreasonable rates

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[114] 16 U.S.C. § 824e (1994).

[115] *Id.*

[116] *San Diego Gas & Electric Co.*, 93 FERC ¶ 61,121, at p. 61,367 (2000) ("November 1 Order").

. . . ."[117] The Commission found that there was clear evidence that the California market structures and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA. The Commission therefore proposed specific remedies to address the dysfunctions it found in California's wholesale bulk power markets.

Furthermore, NPG asserts that in its December 15 Order, the Commission, hearkening back to the language in *Farmers Union Central Exchange Inc. v. FERC*,[118] stated that rates must fall within a zone of reasonableness, where the rates are neither so low as to be "less than compensatory" nor so high as to be "excessive" to consumers.[119] In Farmers Union, the Court of Appeals explained that:

> When the inquiry is on whether the rate is reasonable to a producer, the underlying focus of concern is on the question of whether it is *high* enough to both maintain the producer's credit and attract capital. To do this, it must, *inter alia*, yield to equity owners a return "commensurate with returns on investments in other enterprises having corresponding risks, "as well as cover the cost of debt and other expenses . . . [W]hen the inquiry is whether a given rate is just and reasonable to the consumer, the underlying concern is whether it is

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[117] *San Diego Gas & Electric Co.*, 93 FERC ¶ 61,121, at p. 61,366 (2000) ("November 1 Order"); *see id.* at pp. 61,349-50.

[118] 734 F.2d 1486 (D.C. Cir. 1984).

[119] *San Diego Gas & Electric Co.*, 93 FERC ¶ 61,294, at p. 61,998 (2000) ("December 15 Order").

low enough so that exploitation by the [regulated business] is prevented.[120]

The Court went on to explain that, while the "delineation of the 'zone of reasonableness' in a particular case may, of course, involve a complex inquiry into a myriad of factors . . . the most useful and reliable starting point for rate regulation is an inquiry into costs. . . . [And while] non-cost factors may legitimate a departure from a rigid cost-based approach . . . . 'each deviation from cost-based pricing [must be] found not to be unreasonable and to be consistent with the Commission's [statutory] responsibility.'"[121] In essence, the Court held that, at least as a starting point, and absent evidence to the contrary, prices are "excessive" to the extent they exceed costs plus a reasonable return on capital.

In its December 15 Order, the Commission found that the "[t]he electric power situation in California has worsened since our November 1 Order was issued and it is critical" that immediate steps be taken.[122] The Commission found that, unless remedial measures were taken, "wholesale markets will continue to be dysfunctional."[123] In making this determination, NPG asserts, the Commission satisfied the requirement set forth in Section 206 of the FPA,[124] that it first must find that existing rates are unjust and unreasonable before it may determine

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[120] *Farmers Union*, 734 F.2d at 1502, quoting *City of Chicago v. FPC*, 458 F.2d 731, 750-51 (D.C. Cir. 1971).

[121] *Id.*, *quoting Mobile Oil Corp. v. FPC*, 417 U.S. 283, 308 (1974).

[122] *San Diego Gas & Electric Co.*, 93 FERC at p. 61,981.

[123] *Id.* at p. 61,982.

[124] 16 U.S.C. § 824e.

and fix the just and reasonable rates. The Commission then determined and fixed the just and reasonable rates by, *inter alia*, establishing a "benchmark price" for certain wholesale sales in California.

In its April 26 Order, the Commission instituted a "west-wide" investigation under Section 206 "into the rates, terms and conditions of public utility sales for resale of electric energy in interstate commerce in the WSCC."[125] After holding a public hearing and receiving comments on the justness and reasonableness of electricity rates in the WSCC, including the Pacific Northwest, the Commission found: "There is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets."[126] Thus, NPG contends, the Commission has already concluded that "a critical interdependence" exists among "the ISO's organized spot markets," which it found "dysfunctional," and "bilateral spot markets" in "the rest of the West," including the Pacific Northwest, and even "the prices in forward markets" in California and the rest of the West.[127] Furthermore, the Commission found:

> What is clear, however, is that a major contribution to the high prices was the deficient market mechanisms initially established by California, and approved by the Commission, that have resulted in

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[125] April 26 Order, 95 FERC at p. 61,365.

[126] June 19 Order, 95 FERC at p. 62,547.

[127] *See also id.* at p. 62,556 (finding that "spot markets" in California and the WSCC "are integrated").

a dysfunctional market place both in California and the remainder of the West.[128]

Therefore, the Commission, after months of inquiry, determined that the "deficient market mechanisms" in California led to "a dysfunctional market place both in California and the remainder of the West," including the Pacific Northwest. According to NPG, it is not the purpose of this preliminary evidentiary proceeding, which the Commission ordered conducted under very serious time constraints, to examine and redetermine, yet again, that the Pacific Northwest spot markets are integrated with, and the prices in those markets were rendered dysfunctional and unjust and unreasonable by, the operations of the California spot markets. NPG avers that the Commission has found that prices charged for spot market sales in the Pacific Northwest were unjust and unreasonable.

Moreover, in its June 19 Order, the Commission took action as a result of its Section 206 investigation findings and "prescribe[d] price mitigation for spot markets throughout the West."[129] Before it could determine and fix just and reasonable prices in the Western spot markets, the Commission had to find, as required by Section 206, that the prices in the spot markets throughout the West, including the Pacific Northwest, were unjust and unreasonable.[130] As

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[128] *Id.* (emphasis added).

[129] June 19 Order, 95 FERC ¶ 61,418, at p. 62,545.

[130] As the Supreme Court has stated, "[t]he condition precedent to the Commission's exercise of its power under [FPA Section] 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential.'" *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956). *See Papago Tribal Utility Authority v. FERC*, 610 F.2d 914, 923 (D.C. Cir. 1979)

noted, in the June 19 Order, the Commission found "a dysfunctional market place in California and the remainder of the West."[131] The Commission further acknowledged making such a finding when it stated that its prescribed price mitigation "will guide the WSCC's energy markets through the difficult process of self-correction."[132] Accordingly, unjust and unreasonable prices not only "may" have been charged for spot market sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001, the Commission has in fact found that unjust and unreasonable prices were charged during that period for such Pacific Northwest spot market sales.

On July 25, 2001, the Commission established a method for calculating the just and reasonable clearing prices that should have been charged in the California markets for the period while those markets were dysfunctional.[133] In keeping with the teachings of *Farmers Union*, the Commission established a method for determining the just and reasonable prices that was based on the marginal *costs* plus certain *cost* adders for operations and maintenance, and creditworthiness. The Commission established a further proceeding to determine appropriate refunds based on that just and reasonable pricing methodology.

("condition precedent" to Commission's exercise of powers under Section 206(a) is a finding that existing rate is unjust and unreasonable); *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 187 (D.C. Cir. 1986) (Commission may only order prospective relief under comparable Section 5 of Natural Gas Act "if it finds a previously accepted provision unlawful").

[131] June 19 Order, 95 FERC at p. 62,556.

[132] *Id.* at p. 62,545.

[133] July 25 Order, 96 FERC ¶ 61,120, at pp. 61,516-19.

In the same July 25 Order, the Commission established the instant "preliminary evidentiary" proceeding to facilitate the development of a factual record "to determine the extent to which the dysfunctions in the California market may have affected decisions in the Pacific Northwest."[134] The testimony and exhibits admitted in this proceeding, NPG alleges, confirm the Commission's finding that "the deficient market mechanisms initially established by California . . . resulted in a dysfunctional market place" in the Pacific Northwest,[135] and that "[b]uyers in the Northwest paid outrageous prices for power that caused much economic dislocation."[136]

There is substantial evidence in the record in this proceeding NPG asserts, confirming that (1) the Pacific Northwest and California operated as an integrated market; (2) Pacific Northwest spot market prices and daily price indices such as the Dow Jones Mid-Columbia Electricity Price Index were significantly affected by the prices in the dysfunctional California spot markets; and (3) the Pacific Northwest spot market prices were well-above prices that would have reflected the sellers' marginal costs, resulting in excessive charges of approximately $2 billion during the December 25, 2000 through June 21, 2001 refund period identified by the Commission.[137]

Both NPG witnesses and TFG witnesses testified that the California and Pacific Northwest markets

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[134] July 25 Order, 96 FERC at p. 61,520.

[135] June 19 Order, 95 FERC at p. 62,556.

[136] July 25 Order, 96 FERC at p. 61,522 (Massey, Comm'r, dissenting in part and concurring in part).

[137] *See* July 25 Order, 96 FERC at p. 61,520 n.75.

were integrated.[138] California's witness, Dr. Frank Wolak, similarly testified that "California and the Pacific Northwest are best thought of as a single integrated market."[139] There is overwhelming evidence in the record in this proceeding that confirms the Commission's previous finding that California and the WSCC market are integrated, NPG maintains.[140]

Additionally, NPG argues that the record is replete with evidence that the dysfunctional prices in the California spot markets substantially affected Pacific Northwest spot market prices and daily price indices.[141] Dr. Wolak explained:

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[138] For NPG witnesses, *see, e.g.*, McCullough Rebuttal Testimony, NPG-68 at 18 ("[f]or most of the year . . . the Pacific Northwest is part of the California market"); Movish, NPG-45 at 13, line 5 (discussing "'spillover' effect" between California and Pacific Northwest "sub-market[s]" of the WSCC); Saleba, NPG-53 at 5 (discussing the "influence" and "impact" of California prices on other subregions in the WSCC). For the TFG witnesses, *see, e.g.*, Van Vactor, ENR-1 at 7-8 ("dependence on seasonal exchange has also created a single continuous market"); Adamson, ENR-10 at 19 ("[t]he PNW market is generally integrated with other sub-regional markets in the WSCC"); *id.* at 23 ("the PNW spot market is a component of a larger market that extends to California, the Rocky Mountain States and the desert Southwest"; Jones, PPL-1 at 17-18, lines 19-20 (acknowledging "the close correspondence between price movements in California and the PNW"); *see also* Puget Complaint at 7 ("California and the Pacific Northwest are part of the substantially integrated wholesale power market of the Western Interconnection").

[139] CAL-5 at 10, lines 4-5.

[140] *See* June 19 Order, 95 FERC at p. 62,556.

[141] *See, e.g.*, McCullough, NPG-1 at 9 ("[s]ince May 2000, the centralized markets in California have been the basis of pricing throughout the WSCC"); Movish, NPG-33 at 13, NPG-45 at 13 ("the higher [California] auction prices resulted in a 'spillover'

> Particularly during the winter and spring of 2001, there were very few hours when there was congestion from the Pacific Northwest into California. Even during the summer of 2000, there were few hours when there was congestion from the Pacific Northwest into California. For this reason, when prices in California reflected the exercise of market power, prices in the Pacific Northwest were at the same and often higher levels.[142]

In particular, the high prices in the dysfunctional California spot markets drove up the prices of the longer term, *e.g.*, daily, weekly, monthly, quarterly, and yearly standardized products traded in the Pacific Northwest spot market.[143] As Mr. McCullough testified, "while the causes may be subjective, the logical implication is that, as fundamentals declined in value as an explanation for prices in California, traders were forced to depend increasingly on trends in their estimates of future prices"), NPG argues.[144]

The prices in the California spot markets similarly affected the Pacific Northwest daily price indices,

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effect into the PNW sub-market. PNW power suppliers were able to price at the CAISO and PX price. Prices would have been lower in a functionally competitive market"); Saleba, NPG-53 at 3 ("Because California has such a strong influence in the WSCC, price movements in California tend to have an immediate impact on prices in other sub regions.").

[142] Wolak, CAL-5 at 9, lines 14-20.

[143] *See* McCullough, NPG-1 at 9 ("the opportunity cost of the [California] hourly market clearly drives longer term offers elsewhere in the WSCC"); *id.* ("[a]fter May 2000, the correlation between short term and long term prices has increased).

[144] *Id.* at 9; *see id.* at 9-10 (discussing and graphing the correspondence between Dow Jones daily prices and the related third quarter bids to Seattle).

such as the Dow Jones Mid-Columbia Price Index. The Commission staff, examining peak prices for the summer 2000 period, found that

> "[t]he correlations between California PX prices and western market bilateral prices are quite strong .... Mid Columbia (prices) are highly correlated as are CalPXSP15 and Palo Verde because of the geographic proximity of the points and the general absence of transmission limits into California."[145]

Data from December 2000 and January 2001 shows the continued strong correlation between California prices and Mid-Columbia and California-Oregon Border ("COB") prices, demonstrating that "sellers of electricity will arbitrage any significant price difference between the Pacific Northwest and California."[146]

Thus, in the very few weeks that have been provided for this preliminary evidentiary hearing, NPG states, the parties have produced substantial evidence confirming the Commission's earlier findings that the prices in the dysfunctional California spot markets directly affected the Pacific Northwest spot market prices and daily price indices.

NPG maintains that its members have submitted substantial evidence that prices they paid in the Pacific Northwest spot market during the refund period were significantly above benchmarks based on the marginal cost of the last unit that would have been dispatched absent the price distortions in the California PX and ISO spot markets or that was dis-

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[145] Staff Report to the FERC on Western Markets and the Causes of the Summer 2000 Price Abnormalities, November 1, 2000 at p. 3-8, quoted in Movish, NPG-33 at 13, NPG-45 at 13.

[146] Wolak, CAL-5 at 10; *see* CAL-7 (showing data in bar graph form).

patched, and therefore that such charges were unjust and unreasonable. On behalf of Seattle City Light, Mr. McCullough determined the marginal cost of the highest cost unit that would have been dispatched to meet actual load during the refund period absent the California spot market dysfunctions.[147] Mr. McCullough determined the benchmark price for each month in the refund period.[148] Applying these benchmark prices to its actual sales and purchases, Seattle City Light determined that it was a net purchaser and would be entitled to refunds totaling $278 million.[149]

On behalf of Tacoma, the Port and Northern Wasco, Mr. Movish determined a mitigation price similar to that used in California by the Commission, but modified in certain respects to reflect characteristics of the Pacific Northwest.[150] Using this mitigation price reflecting the marginal cost of the marginal unit, Tacoma, the Port and Northern Wasco calculated that they were entitled to refunds totaling $65,407,755; $9,371,660; and $4,089,364, respectively.[151]

In calculating their potential refunds in this proceeding, the California parties used the unadjusted mitigated market clearing prices calculated by the California ISO and submitted in Docket No. EL00-

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[147] *See* Part II.F.1 *infra* (describing this benchmark in detail).

[148] *See* Exh. NPG-1 at 16-17.

[149] Item by Reference NPG-70 at 2, para. 1.d.

[150] *See* Part II.F.2, *infra* (describing Mr. Movish's benchmark in detail).

[151] *See* Movish, Exh. NPG-33 at 24-25; Movish Exh. NPG-45 at 24; Winters, Exh. NPG-43 at 12; Item by Reference NPG-71 at 25.

95-045 on August 9, 2001.[152] Using this benchmark price, the California parties determined that they paid $1,466,098,964 in charges above the just and reasonable rate adopted by the Commission for California.[153]

In calculating its amount of potential refunds, the Eugene Water and Electric Board ("EWEB") used as its benchmark price the non-emergency hour mitigation price of $91.87 calculated by the California ISO.[154] EWEB found that it had incurred charges of $39,719,000,[155] over this benchmark price.

The Sacramento Municipal Utility District ("SMUD") calculated its potential refund amount using its "estimate of the ISO's hourly market mitigation clearing price."[156] Using this benchmark, SMUD calculated its potential refund to be $4,587,511.72.[157]

In sum, the parties who, to date, have calculated the potential net refund amounts described above have done so using mitigated prices or "benchmarks" based on the marginal cost of the last unit that would have been dispatched, absent the price distortions in the California markets, or was dispatched. These benchmarks are either identical or akin to that used by the Commission in the California refund proceeding as the demarcation line between fair and reason-

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[152] William Green, Exh. CAL-1 at 3, lines 1-2 and 6, lines 9-23.

[153] Exh. CAL-1 at 7, line 1.

[154] *See* Spettel, Exh. NPG-74 at 12.

[155] *See* Commission Staff Exh. S-8; Spettel, Exh. NPG-74 at 12, lines 3 through 5.

[156] Exh. SMD-1 at 4, lines 4-5.

[157] *Id.* at 2.

able, versus unjust and unreasonable, prices. The parties have thus submitted substantial evidence of unjust and unreasonable charges which, as the Commission staff found, merits further proceedings.[158] The total extent of potential refunds claimed to date is $1,931,354,858, as set forth in Commission Staff Exh. S-8, from which the following summary is taken:

California Parties—$1,466,098,964

City of Seattle, Washington—$278,000,000

City of Tacoma, Washington—$65,407,755

Clark Public Utilities—$64,080,603

Eugene Water and Electric Board—$39,719,000

Northern Wasco County—$4,089,364

People's Utility District Port of Seattle, Washington—$9,371,660

Sacramento Municipal Utility District—$4,587,512

TOTAL $1,931,354,858

California Parties

According to the California Parties, the record in this case establishes unequivocally that unjust and unreasonable prices were charged for spot market bilateral sales in the PNW during the refund period. The TFG's arguments to the contrary erroneously assume that the PNW market was not affected by the documented dysfunction in the California market, and that the extraordinarily high PNW prices merely represented the operation of a distinct and "workably competitive" market. These claims disregard the obvious and are unsupported by the record in this case.

[158] *See* Poffenberger, Exh. S-3 at 10.

TFG

TFG maintains that even if one were to ignore the serious legal prohibitions on directing retroactive refunds, any effort to argue that unjust and unreasonable prices may have been charged, can only proceed on the strength of a full understanding of the unique characteristics of the PNW market and the context in which prices evolved during the period from December 25, 2000 through June 20, 2001.

The PNW is part of the broader Western power market. The purchase and sale of electricity is carried out pursuant to the rules and guidance of the WSPP. Implementation of the WSPP Agreement was first approved in 1987, but for decades previous the PNW has enjoyed a robust and liquid wholesale power market, which is characterized by hundreds of informed and experienced traders and multiple trading points. *See* Exh. ENR-1 at 3; Exh. AE-1 at 3; Western Systems Power Pool Agreement, Exh. S-6 (Original Sheet No. 91, Rate Schedule FERC No. 6, at 101-103). As Seattle's own witness Mr. McCullough testified:

> The Pacific Northwest operates as a true commodity market where prices are set by bilateral negotiations, rather than administered by a separate authority. In this way, the Pacific Northwest far more closely approximates true commodity markets like the Chicago Board of Trade or the London Metal Exchange.
>
> Exh. NPG-1 at 7:14-17.

Several factors explain this phenomenon. In terms of energy resources, over 60% of the PNW's power supply comes from hydroelectric facilities in a typical year. Exh. ENR-1 at 8; Exh. ENR-5. While the

prevalence of hydroelectric generation provides a distinctly inexpensive source of power, it also subjects load serving entities to the vicissitudes of weather (*i.e.*, drought and resulting low-flow conditions). Faced with seasonal and year-to-year variations in water and storage availability, PNW parties have long been accustomed to buying and selling with each other and with parties outside the region to ensure that supply matches demand. Exh. AE-1 at 3.

Following construction of the Northwest-Southwest Inertia in 1970, seasonal exchanges of power with California, Arizona and New Mexico became commonplace. The normal water flow from May to July, coupled with a winter peaking demand profile, has enabled the PNW to export large volumes of "economy" energy during summer months, when its loads are low, but loads to the south are at their highest levels. In return, the PNW historically has relied on surplus thermal generation from California and the Desert Southwest to supplement local supplies during winter cold spells, when loads to the north are high in comparison to loads to the south. Exh. ENR-1 at 9.

The presence of an extensive and comparatively uncongested transmission network (on a historical basis) also has contributed to the development of a fluid wholesale power market in the PNW. BPA owns and operates the majority of the high voltage transmission facilities in the region. Long before the advent of Commission Order No. 888,[159] BPA allowed

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[159] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10,

parties access to its transmission grid. Exh. AE-1 at 3. As a consequence, the Mid-Columbia hub in Eastern Washington is recognized as one of the most flexible trading points in the nation. Exh. ENR-1 at 12.

Because a robust bilateral wholesale market evolved on its own, there has never been a centralized power exchange in the PNW. As a result, there is no single market clearing price in the region. Exh. ENR-10 at 12. Instead, energy is bought and sold continuously on a bilateral basis, subject only to the principles set forth in the WSPP agreement. Each utility is free to choose how to meet its firm load requirements as it sees fit and no one is captive to a single market or a single point of supply. As noted by Eugene Water and Electricity Board ("EWEB") witness Spettel, transactions "are negotiated at arms-length between willing buyers and sellers . . . [and] oftentimes reflect unique and specific circumstances between the parties engaged in each transaction." Exh. NPG-68 at 7. *See also* Tr. at 566-67; Exh. ENR-1 at 13; Exh. PWX-1 at 21; Exh. BPA-1 at 22; Exh. ENR-10 at 11; Exh. IE-2 at 13; Exh. PPL-1 at 21.

Given the availability of many traders and trading points, purchasers in the PNW have numerous options in developing a portfolio of power supply. Depending upon their perceived needs and tolerance for risk, load-serving entities can buy power for the next hour, the next day, the balance of the month, monthly, quarterly or for a term of one or more years. Exh. NPG-74 at 6. As observed by Dr. Tabors, risk-averse load-serving entities can assemble a portfolio

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1996), *FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996* ¶ 31,036 (1996) ("Order No. 888").

of long, medium and short-term contracts and, thereby, minimize their exposure to volatile spot market prices. Exh. PWX-1 at 21. In the PNW, shortages in the availability of hydroelectric generation are constantly assessed and general trends are predicted months in advance, consequently PNW purchasers tend to make extensive use of forward contracts (*i.e.*, transactions with durations longer than 24 hours). Indeed, over 99% of the City of Seattle's net purchases during the December 25, 2000-June 20, 2001 period were made under forward contracts; the corresponding figure for Tacoma Power approximates 62.5%. Exh. PWX-3.

Two additional characteristics of the PNW market are directly relevant to the justness and reasonableness of bilateral spot market prices in the region. First, demand in the region is more price sensitive (that is to say, "elastic") than in other parts of the West due, in part, to the presence of a number of energy intensive industries, such as aluminum smelting. Exh. ENR-1 at 11. Those consumers have exercised and, indeed, regularly exercise their ability to respond to price signals by decreasing consumption. Demand responsiveness by PNW consumers was a very important factor in bringing prices down in the PNW in 2001, and an important indicator that the PNW markets were functional throughout the potential refund period. Second, prices, particularly in the forward markets, are extremely sensitive to movements in the cost of natural gas. Exh. ENR-10 at 24-27. It is, therefore, not surprising that electric prices rose dramatically in the PNW when increased demand for natural gas caused prices to skyrocket in the latter part of 2000, as drought conditions restricted the availability of hydroelectric generation.

The Commission's decision to address refunds in Docket No. EL00-95-004 (the "California proceeding") was based, at least in large measure, on its conclusion that the "electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed."[160] The Commission found problems with (i) California's implementation through the ISO and PX, of a mandatory single price auction mechanism, and (ii) the exclusive reliance on spot market (less than 24 hour) trades for purposes of establishing that price. These problems distorted and exacerbated the effects of high prices that resulted when supply was tight. Of particular relevance to this investigation, the Commission expressly declined to impose refund liability on bilateral purchases of the CDWR after the PX closed its doors:

> We believe imposing after-the fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding when the Commission consistently encouraged California load-serving entities to acquire a balanced portfolio of short, medium and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000, through June 20, 2001 to include transactions outside the ISO and PX centralized markets would simply hinder the ability of parties to enter into new bilateral contracts.[161]

Multiple requests for rehearing have been filed in the California proceeding and the disputed issues addressed therein cannot and should not be relitigated here. TFG argues that what can be said—

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[160] November 1 Order, 93 FERC at p. 61,349.

[161] July 25 Order, 96 FERC at p. 61,515.

indeed, must be said—is that the Commission's rationale in its July 25 Order for ordering refunds in the California ISO and PX centralized spot markets is simply not applicable to the PNW market, but its reasoning regarding bilateral contracts is compelling outside those markets.

The factual differences between the California ISO/PX markets and the PNW market are stark and self-evident. In California, load-serving entities (comprised almost entirely of California's three large investor-owned utilities) were forced to divest much of their generation, to sell power from what generation remained to the ISO/PX and then buy back all of their requirements through a centralized clearing house at an administratively determined price. Because that price was tied to the bid of the most-expensive generating unit operating within the market at the time, it did not necessarily reflect the value placed on those transactions by any individual buyer. Exh. PWX-1 at 16. In addition, having to rely entirely on spot market sales, California buyers were effectively prevented from hedging their risks or balancing their portfolio through forward contracts. In its November 1, 2000 Order,[162] the Commission expressly found this to be a fundamental problem with the California market. Exh. ENR-10 at 11.

In sharp contrast, buyers in the PNW faced no such constraints. Load-serving entities, for the most part, retained their own generation, were free to negotiate supply contracts on their own terms and conditions in spot and forward markets, and, as a consequence, paid prices that reflected the value that willing buyers and sellers placed on those transac-

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[162] November 1 Order, 93 FERC at p. 61,359.

tions in the face of supply constraints. Exh. PWX-1 at 16. For many years PNW buyers have been free to enter into short, medium, and long-term contracts to achieve a hedged and balanced portfolio. It is undisputed that "participants in PNW markets made their own decisions regarding purchasing strategies and contract terms, not only in the period covered by this proceeding but for years leading up to this period." Exh. PWX-1 at 6:14-16. The participants "made numerous conscious decisions regarding their electricity supply strategy in the years and months prior to the period covered by this proceeding, as well as the during the period itself." *Id.* at 7:8-10.

All of the credible testimony shows that a confluence of unprecedented demand and supply conditions in the PNW led to increased electricity prices during December, 2000 to June, 2001.

The hearing record documents in detail the successive shocks that the western power market experienced leading up to and during the period at issue:

> The disruption and price explosion in the WSCC from May 2000 through June 2001 were the consequence of market fundamentals, exacerbated by financial uncertainty and confusion. There were four compounding events that caused price to rise and to remain at elevated levels for fourteen months. In the first wave, the summer of 2000, high demand growth and hot weather combined to create capacity shortages in California, with resulting price spikes. In the second wave, cold weather smacked the PNW earlier than expected and with much greater severity than normal. The cold weather coincided with the season in which the natural stream-flow in the region's hydro system is at its lowest, and with the planned reconditioning

of many of California's thermal generators due to heavy usage in the summer of 2000. The natural gas delivery system was stretched to its limit, inventories reached historic lows, and gas prices peaked at thirty times the level of the year before. In November and December, precipitation remained at record low levels and the power industry became increasingly anxious about the possibility of a serious drought. The Power Planning Council's October warning appeared all the more prescient. In January 2001, the first formal projections on snow pack became available and provided alarming evidence of dry conditions, bringing a third wave of dread to the Western power market. In the meantime, PG&E and Southern California Edison were not able to pass on to their customers the high prices they had had to pay for power in November and December due to frozen rates imposed during market restructuring. Both utilities defaulted on their obligations to their suppliers, including many PNW utilities. The growing financial risk created the fourth and final wave, as essential trade shrunk and the WSCC split apart in autarky.

Exh. ENR-1 at 19:13-20:11.

TFG continues to assert, assailed by these shocks, the PNW market did not malfunction, as did the California market. To the contrary:

The PNW was faced with an extreme and rare contraction in available supply. To accommodate the shortage, prices rose dramatically, but that is exactly what they are supposed to do. Higher prices provoked a drop in demand and an increase in alternative supplies. Once it was clear that the functions of demand and supply would accommo-

> date the projected shortfall, prices collapsed with extraordinary speed.

Exh. ENR-1 at 19:13-21:1; *see also* Exh. NPG-16 at 16:327-17:349; Exh. IE-2 at 2:22-3:4; Exh. IE-4, Appendix F.

The market for electricity in the PNW was affected to varying degrees by these factors, all of which worked together to raise the price of electricity as is normally expected in a workably competitive market when supply is scarce.[163]

Importantly, the evidence also establishes that the PNW utilities were generally forewarned of potential supply shortages:

> Power supply in the region is tied irrevocably to precipitation in drainage areas of the Columbia River. From 1996 through 1999, weather patterns had produced a series of above average water flows and the surplus generation was giving misleading signals. It had been over two decades since the region had experienced a major drought, population growth had increased demand and, perhaps unknowingly, the PNW had become increasingly dependent on seasonal trade. Moreover, declining salmon runs and the risk of species extermination had caused the region's policy makers to shift focus. The commitment to save the salmon, however, required the PNW to implement new and untested hydroelectric operational modes.

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[163] Dr. Cicchetti testified: "Dr. Wolak and others ignore this competitive market price signal function, which only works when conditions that drive up prices such as excess demand, short term supply or both, are allocated to signal the need for new investments by prices (MCP) that exceed short-run marginal cost and ATC. This outcome is efficient and serves a valuable public policy function." Exh IE-2 at 25-26.

> Early in 1999 the BPA Administrator met with the Power Planning Council ("Council") and expressed concern that the region showed an energy deficit even under normal water conditions. On page 2 of the Council['s] "Northwest Power Supply Adequacy/ Reliability Study" of March 6, 2000, it was reported that the BPA study revealed that in eighty percent of the simulated historical water flows there was a projected deficit averaging 2,500 megawatts per hour for September while thirty-six percent of the scenarios for the month of February had an average deficit of 3,800 megawatts per hour. On page 3, the Council reported that its own analysis had reached nearly identical conclusions. . . . The Council's white paper was accompanied by a "Keep The Lights On" conference attended by executives from many PNW utilities. At the conference the BPA Administrator again warned of inadequate supply. Moreover, the audience was warned about the impact of fish preservation requirements on dam operations as well as planned curtailments of the federal transmission system. In its March 6, 2000 edition, *Clearing Up* reported that Seattle City Light Superintendent Gary Zarker took the threat of shortages seriously and "that the region should approach the reliability situation 'as if the crisis had already occurred.'"
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> Exh. ENR-1 at 13:22-15:2.

TFG asserts that even the refund claimants' evidence establishes that drought conditions were severe and affected wholesale electrical energy prices:

> • "While power prices have been high, the Pacific Northwest also experienced one of the driest years on record which in turn reduced the amount of power available from Pacific Northwest hydroelec-

tric projects . . . Power prices would be expected to be lower in years where more normal precipitation increases the supply of electricity, thus depressing power prices in average or better-than-average hydrological conditions." Exh. NPG-74 at 9:21-10:5.

- "In October, 2000, the utility received less than normal rainfall, and in November and December our drainage basin received significantly less than half of the statistical average precipitation for these months . . . These shortfalls forced SCL on the market for additional purchases at even higher prices." Exh. NPG-4 at 14:305-310.

- "The ultimate blow to the western wholesale electricity market came when winter rains failed to materialize. A dry fall turned into a dry winter and left the Pacific Northwest running on empty reservoirs by spring. The traditional trading patterns between California and its northern neighbors—electricity shipped from the Northwest to California in the summer and returned by California to the Northwest in the winter—failed." Exh. NPG-16 at 16:361-366.

TFG points out that NPG witness Ms. Green testified, Seattle would typically prepare for potential electricity shortages by monitoring water levels:

Q: Do you know when Seattle City Light realized that low water year was about to materialize for 2001?

A: Most of our precipitation comes in the months of October through March, so October was the first month in which we were expecting significant precipitation in which it did not occur. In November, we had a similar shortfall. In December, we also had a shortfall. And then, as my testimony indi-

> cates, the snow surveys that we viewed, and have done for 50 years, showed a declining water position every month that we measured the snow.
>
> Tr. at 592:19-593:4.

As Ms. Green and others acknowledged, in 2000 and 2001, the PNW experienced the worst drought in the last 50 years. *See* Tr. at 592:19-593:4; *see also* Tr. at 610:20-611:10. Combined with increased demand from population and technology growth ("one dot-com company can use 20-40 megawatts per day, the same as the entire [Seattle-Tacoma] airport."), this drought caused an unprecedented increase in prices. Tr. at 610:20-611:10. The record also establishes that increased demand for electricity contributed to increased input costs (*i.e.*, higher demand for electricity resulted in higher demand for natural gas, causing the price for gas to increase). *See* Exh. ENR-10 at 28:4-5, 12-15 ("In addition to dramatic changes in market conditions for natural gas in the Northwest, a second major factor that must be considered is the impact of hydrological conditions. . . . Just as the natural gas market was making it more costly to offer forward electricity contracts, the weather was reducing the ability of hydroelectric operators to enter into such forward commitments. Available supply was therefore contracting, which put further upward pressure on prices.").

In addition, in California, increased demand, unavailable generation, and credit concerns with California buyers all exacerbated the situation. As Clark Public Utility's witness Gary Saleba testified:

> Several factors combined to exacerbate the problem: the fact that significant amounts of capacity were out of service in California for maintenance or other reasons; the fact that financial crises facing

> California's two largest purchasing entities (both IOUs) led some sellers to withhold supply because of inadequate credit assurances; and the collapse of the California PX Day Ahead market.

Exh. NPG-53 at 5:4-10.

The record evidence amply demonstrates that the PNW market for spot sales of electrical energy was at all times between December 25, 2000 to June 20, 2001 competitive and functional. Dr. Tabors explained why:

> [P]rices within the Pacific Northwest are established through bilateral contracts. Buyers are not captive to a single market and certainly not a single point of supply. There are multiple trading points in the Pacific Northwest and individual trades can take place at any other point that the two trading partners might choose. The result is that the structure of the Pacific Northwest spot market is functional and is inherently more competitive and far more flexible than was or is the California spot market. Participants in the Pacific Northwest market had a vast number of alternatives for purchases that were not available in the California market.

Exh. PWX-1 at 20:16-21:3.

Dr. Tabors' analysis and conclusion is fully consistent with that of other experts. Dr. Jones explained that, the "classic definition of a competitive market is a market that relies on the interaction of many informed buyers and sellers such that no single buyer or seller can institute and profitably sustain a significant increase in price." Exh. PPL-1 at 7:12-14. Using this rule, Dr. Jones found no evidence to sup-

port claims that the PNW market was other than workably competitive:

> Based on my analysis, I conclude . . . the actions of sellers and the prevailing prices in the PNW are fully consistent with a competitive market and are an attempt on the part of buyers and sellers to allocate scarce resources efficiently.
>
> * * *
>
> There has been no showing of market power or other evidence indicating members of the TFG did any thing other than reflect their competitive market expectations in their bilateral contracts.

Exh. PPL-1 at i.

Dr. Jones explains that in the PNW, buyers and sellers of wholesale electricity can, at any time, negotiate using established and transparent terms. *Id.* at 7:14-18. He showed that prices during the relevant period were a function of normal supply and demand conditions, which were largely unprecedented:

> The prices set by the marketplace from December 2000 through June 2001 reflect the actions of buyers and sellers in a competitive market responding to forces other than market power.
>
> * * *
>
> [A]fter years of abundant generation capacity that caused prices to remain low, the market began to change in the late 1990's as continued growth in electricity demand began to 'bump against' the ability of low-cost generators to meet peak load requirements at existing prices.

Id. at 12:15-14:13; 29:12-15; 13:15-18.

However, Dr. Jones, along with nearly all other witnesses, determined that the PNW market, con-

fronted with these conditions, performed just as a workably competitive market would, TFG avers.

- "As prices increased during 2000-2001, investors/suppliers responded, proposing new capacity additions. On the demand side of the price signal, consumers went to work, reducing energy use and adopting conservation techniques. . . . As a consequence of this competitive response, prices for electricity in the PNW have fallen dramatically." Exh. PPL-1 at 14:7-13.

- "Notwithstanding the shortages of energy in the Pacific Northwest, the market was sufficiently competitive to enable purchasers to be selective about the energy product that they were purchasing. As a consequence, purchasers were able to dictate certain key terms of transactions to sellers, such as firmness and point of delivery." Exh. PSCO-1 at 11:12-16.

- Port of Seattle reported in May 2001, "[m]any experts are forecasting not only sustained periods of high prices but also shortages of electricity in 2001. Staff believes it is critical that we not only take measures to reduce the cost of electricity through conservation . . . , but find a reliable and stable source of electricity for the Airport's future needs." Exh. TFG-8 at 1, PS 1570.

- Port of Seattle also reported "[f]our different companies have approached us on . . . the option of self-generation . . . . Implementing energy conservation projects and programs [has] reduced [our] consumption by over 10% already and may get to 15% in another month. Long term we believe we can reduce energy consumption by 20-25% from our current base." Exh. TFG-5 at PS 1529.

As a result of these fully predictable market responses, the supply and demand were restored to balance in short order. Mr. Van Vactor also explains how the Western power market crises moderated:

> The Western power crisis has alleviated due to a significant drop in consumption. In the PNW, many industrial customers agreed to shut their plants down and sell the power back to the supplier. In California, the long-postponed retail rate increase finally went into effect in June [2001]. That combined with a conservation program dropped demand by more than five percent. At the same time new, and more efficient, generating resources came on-line. Summer weather returned more or less to normal and spot prices have returned to normal levels.
>
> The PNW was faced with an extreme and rare contraction in available supply. To accommodate the shortage, prices rose dramatically, but that is exactly what they are supposed to do. Higher prices provoked a drop in demand and an increase in alternative supplies. Once it was clear that the function of demand and supply would accommodate the projected shortfall, prices collapsed with extraordinary speed. Exhibit ENR-9, compares an index of the price of the third quarter 2001 forward contract power delivered to Mid-C to an index of "Dot-Com" stock prices. Once the western power market corrected it did so with a vengeance reflecting, once again, unpredictable Mother Nature and the awesome power of markets to accommodate her.

Exh. ENR-1 at 20:14-21:6. Dr. Tabors observed the same moderation of the market:

> [T]he bilateral markets in the PNW, . . . which have been in existence for more than two decades,

> worked through a confluence of adverse circumstances in 2000 and 2001, and have now regained equilibrium. Conservation resulted from price signals, demand was reduced, load was shed, and prices came down. These are not indications of a broken market in the PNW, but of one that works. It should be left alone to function.

Exh. PWX-12 at 10:6-11. Additionally, Dr. Jones observed:

> The price signals sent to buyers and sellers in the spot market for electricity in the PNW are sufficiently strong to cause forces to be put into place that will change the structure and nature of the wholesale market so that the price spikes are unlikely to reoccur.

Exh. PPL-1 at 5.

Moreover, on cross-examination, the claimants' witness, Dr. Mason, conceded that sellers who engaged in the business of marketing electrical power face no barriers to entry. *See* Tr. at 770:24-772:3. Dr. Mason testified unconditionally that for sellers who are marketers that "[t]here are no barriers to prevent them [from] buy[ing] and resell[ing]." *Id.* Likewise, another of the claimants' witnesses, Dr. Pechman, admitted that he conducted no econometric or price elasticity studies to support his contention, contrary to the evidence, that demand in the PNW does not respond to price:

> **Q:** Where in your testimony—I'm going to open it up. I want to look at a line or a line or an exhibit in your testimony, where do you prepare and present to this court an economic analysis of the elasticity of demand for wholesale power in the Pacific

Northwest market during the period at issue, where?

A: I have no such analysis in this testimony. Tr. at 1030:2-9. Similarly, Dr. Pechman admitted that he had no evidence to support his assertion that suppliers exercised market power by withholding power from the market:

Q: Let me just ask, in your testimony in this proceeding, do you provide any evidence of joint action by suppliers of wholesale electricity to the Pacific Northwest market during the period at issue? Do you provide any evidence of joint action by suppliers?

A: No.

Id. at 1030:20-25.

According to TFG, claimant's arguments are based not on any proof that the PNW market was somehow flawed. In fact, the evidence proves the opposite. Seattle witness Mr. McCullough observed:

One reason why real world commodity exchanges avoid the administered prices of the California model is that these types of markets have proven relatively easy to manipulate. Manipulation of prices in the WSCC outside of California is difficult since no central authority can be "gamed."

Exh. NPG-1 at 7:19-22. EWEB witness Mr. Spettel echoed this characterization of the PNW:

While the prices in the Pacific Northwest were higher than expected or desired by EWEB, whether EWEB was a purchaser or a seller in a given transaction, the prices were not a result of unreasonable profit taking or unreasonable leverage exercised by a given seller or sellers in the Pacific Northwest market.

Exh. NPG-8 at 8. Nor do refund advocates seek any structural changes in the operation of the markets governed by the WSPP Agreement:

> **Q:** In fact, you're not advancing any challenge to any of the terms and provisions of the WSP agreement, correct?
>
> **A:** Correct.
>
> **Q:** Are there any provisions that come to mind that you think you'd like to have changed in this proceeding?
>
> **A:** No.

Tr. at 660-661.

Rather, claimants' argument reduces to this: Because prices were high in both California and the PNW and because these markets are integrated, prices in the PNW must have been "influenced" by the "flaws" the Commission found in the ISO and PX spot markets. This argument finds causation where none exists. An imbalance between supply and demand caused the high prices throughout the west. The flawed market structures of California exacerbated the effects of scarcity in California, but they were not the cause in either California or the PNW or the rest of the WSCC.

To date, the Commission has taken a surgical approach to the problems in California.[164] It has determined that structural flaws existed in the ISO and PX spot markets and it purported to design a re-

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[164] *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Service into Markets Operated by the California Indep. Sys. Operator and the California Power Exchange*, 95 FERC ¶ 61,115 at p. 61,352 (2001) (the "April 26 Order") ("price mitigation should be as surgical (least intrusive) as possible and last for as little time as possible").

fund order and mitigation plan to cure those flaws. The Commission has rightly refused to extend refund liability to other California markets in which prices were apparently "influenced" by the ISO and PX prices but where no structural flaws existed. For the same reason, refunds should not be imposed in the PNW. There is no evidence, allegation, or finding that any structural flaw at all existed in the PNW market. The Commission should minimize its intervention in otherwise well-functioning market mechanisms.

In seeking refunds, claimants build their arguments on the existence of high prices alone. In doing so, they are trying to shield themselves from the consequences of their own decisions. There is no doubt that refund claimants were aware of the risks they were taking by increasing their reliance on the spot market to serve load. The Commission has said:

> We emphasize that, by design and definition, spot markets must be allowed to reflect the price swings which capture their temporal nature. In markets such as these, which are the closest to when demand must be met, sufficient supply often manifests itself by dramatic price drops while tight supply can produce dramatic price increases. This is the nature of spot markets. *Those who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases.*[165]

Tacoma's witness, Ms. Stegeman, noted explicitly that Tacoma chose to take the risk of high spot

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[165] December 15 Order, 93 FERC at p. 61,996 (emphasis added).

market prices. Tacoma chose not to accept the "environmental risk associated with the operation of the coal burning [Centralia] plant," or the risk of being "locked into a long term contract" at prices above the prevailing spot market price. Exh. NPG-57 at 3. Ms. Stegeman even contended that "a utility should be protected by the FERC for market prices if the utility mismanaged the acquisition of its power supply portfolio." Tr. at 692:9-692:12. The evidence is clear that such intervention is not conducive to a competitive market. As Dr. Cicchetti explains: "Those who seek refunds for anomalous years are looking for a 'heads I win, tails you lose' result." Exh. IE-2 at 23:2-8. If the position of the refund claimants is accepted, they would be relieved of the consequences of their conscious economic decisions at the expense of a functioning competitive market in which a vast majority of the PNW purchasers during this period accept responsibility for the choices they made.

Uncontradicted record evidence, TFG avers, demonstrates that parties seeking refunds chose to increase their risks. Unlike California, *no one* in the PNW was forced to rely solely on spot markets. Those who made spot purchases did so voluntarily, both benefiting and losing from their choices as the market moved up and down.

NPG witness Ms. Green testified that in 1996, Seattle City Light had a "surplus generation position of over 250 MW." Exh. NPG-67 at 3. Over the next four years, however, Seattle chose to dismantle that surplus. Seattle reduced the amount of power it was entitled to take from BPA by 100 MW, and sold its 80 MW share of the Centralia power plant. *Id.* Assuming normal water conditions, Ms. Green admitted that these actions reduced Seattle's projected surplus

for 2001 to just 22 MW. *Id.* In relation to Seattle's average annual load of over 1100 MW and peak load of 1769 MW, this reserve is only 2% of average load and barely 1% of peak load. This is insufficient for a normal water year and sorely deficient for a drought year. Exh. NPG-4 at 8:179-9:195. Seattle recognized in September, 2000 that the Centralia sale left it "more dependent on the market than we have been historically." Exh. PPL-1 at 21 n.19 (*quoting* Seattle City Light, *SCL Issues Brief: Wholesale Power Market Prices and Seattle City Light Rates*, Sept. 19, 2000, at 2).

Tacoma likewise sold its [80 MW] share of the Centralia production. Tacoma replaced this production with purchases from Powerex and BPA—parties from whom it now seeks refunds. Exh. NPG-57 at 3. Neither Seattle nor Tacoma chose to build or acquire generating capacity to replace the Centralia production until after the consequences of their short position became apparent. Seattle also chose to base its supply plans on what turned out to be overly-optimistic projections of water levels, rather than the conservative assumptions available to it. Tr. at 591:20-25.

Purchase of forward contracts was another option available throughout the PNW to reduce reliance on the volatile spot market. Tr. at 656:15-657:4. In September 2000, TFG member Powerex offered forward contracts for delivery of power during the first quarter of 2001 at $75.50 and $81 per MW. Tr. at 689:11-690:21; Exh. TCE-2. One of Tacoma's industrial customers, Simpson Timber, chose to acquire power on these terms, and thus avoided having to acquire this power at the higher spot market prices prevailing in the first quarter of 2001. Tr. at 691:9-

691:14, 700:10-700:22. Tacoma, however, chose not to do so. Tacoma also received quotations for forward purchases from a number of parties in November 2000, but did not take advantage of them. Tr. at 647:10-649:14; Exh. TFG-9. Despite this, Tacoma now asks the Commission to give it, through refunds, rates it rejected in the marketplace. The evidence shows that the claimants, like Tacoma, essentially want this Commission to absolve them of their conscious decisions. The public interest does not provide for such regulatory interventions.

Finally, TFG asserts that refund claimants increased their reliance on the spot market by managing their own resources to pursue goals other than generation of electricity to meet their loads. Ms. Green's testimony referred to Seattle's need to "serve the environmental expectations of our customers." Exh. NPG-67 at 8-9. Measures to do so included implementation of salmon preservation policies that limited the ability of the hydroelectric power system to shape flows in a given month to meet firm system needs. Exh. ENR-1 at 17-18. Although salutary, such choices have a cost, the obligation for which belongs with Seattle and its customers, not its wholesale suppliers.

For a number of years preceding the refund period, wholesale electricity market prices in the PNW were, according to Tacoma's Ms. Stegeman, "quite low." Exh. NPG-16 at 14. *See also* Exh. IE-2 at 28:15-20. During this time, wholesale electric power was often available in the spot market at lower rates than those available through forward contracts and other long-term arrangements. That is why, for example, Seattle chose in 1996 "to take 100 MW off of its BPA entitlement, the cost of which exceeded the market at

that time." Exh. NPG-67 at 3. By electing to rely on the spot market during this period, refund claimants benefited financially (although at the cost of increasing their exposure to the risk of spot market price increases). Tacoma, for example, was able to keep its rate levels unchanged from 1995 to December 2000. Exh. NPG-16 at 12; *see* Exh. PPL-1 at 24 & n.24.

Having now experienced the volatile price increases of the spot market to which they exposed themselves for short-term financial gain, the refund claimants are rebalancing their portfolios by returning to BPA or by acquiring interests in new generation facilities. Seattle has acquired a 100 MW capacity share of a combustion turbine and exercised its right to take its full BPA entitlement. Exh. NPG-67 at 3. A May 2001 Port of Seattle staff analysis concluded that "[b]ecoming a BPA customer is the best long-term strategy for the Airport." Exh. TFG-8 at 2; *see* Tr. at 614:18-614:25. Tacoma has installed a 48 MW diesel generation project and entered into exchange agreements with other power suppliers. Exh. NPG-15 at 18; Exh. NPG-57 at 5. These responses by refund claimants are proof positive that the market is functioning properly and that it continues to offer choices to its participants. The refund claimants could easily have taken these risk-reducing steps sooner; for reasons of their own, they decided not to do so.[166]

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[166] Dr. Pechman likens their position to that of an emphysema patient who should not be forced to pay high prices for oxygen simply "because he knew or should have known that smoking cigarettes could adversely affect his health," Exh. CAL-14 at 8:5-6, but this hyperbole has nothing to do with the refund claimants' situation. If anything, the refund claimants are akin to *hospitals* that sell oxygen to make a quick profit, gambling that they will not need it or can replace it at a low price. Despite Dr. Pechman's attempt to arouse emotions in their favor,

They should not now be reimbursed through an after-the-fact refund for decisions which benefited them for many years, but were "wrong" for a brief time.[167]

Since well before the period at issue both Seattle and Tacoma had over two decades of trading experience in Northwest wholesale markets. Exh. NPG-1 at 17; Exh. ENR-1 at 9. They have large trading operations, and bought and sold millions of kilowatt-hours of electricity in 2000. Exh. NPG-4 at 9; Exh. NPG-16 at 9. Dr. Jones made clear that such entities have many tools available to reduce their exposure to price risk, such as options on forward contracts and financial instruments such as contracts that exchange fixed prices for floating prices and other bilateral instruments. Exh. PPL-1 at 22-23.

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neither his clients nor the other refund claimants have shown why they should not be responsible for their decisions.

[167] *See Entergy Nuclear Indian Point 3 LLC*, 92 FERC ¶ 61,281, at p. 61,946 (2000) ("[W]e see no evidence that this transaction is not the result of arms' length negotiations. We will not require Applicants to insulate their affiliates' customers from the normal business risk that some ventures may involve greater risk than others."); *OXY USA Inc.*, 59 FERC ¶ 61,017, at p. 61,041 (1992) (Commission refuses to intercede in consensual process by which parties renegotiate contracts upon commencement of market-based rates); *Texas Eastern Transmission Corp.*, 55 FERC ¶ 61,482, at pp. 62,603-05 (1991) (rate design that reflects the "consensual allocation of economic risk between the parties" should be implemented unless it is unreasonable because, for example, it was "not the result of an arm's length negotiation," one party was "able to exercise sufficient market power to deprive the customer of a meaningful choice in the matter," or the rate would give one source a "non-market-related, anticompetitive advantage."); *see also Tennessee Gas Pipeline Co. v. FERC*, 824 F.2d 78, 82 (D.C Cir. 1987) (noting the "interest in allowing firms to allocate risk among themselves.").

In support of its contentions TFG asserts that refund claimants made no showing that they were subject to any limitation on their ability to hedge their risks as they saw fit. Dr. Cicchetti identified numerous tools that were available, including New York Mercantile Exchange electricity futures at Cinergy, PJM, Palo Verde, and California Oregon Border, Over-the-Counter (OTC) price swaps, and OTC forward products, which are quite varied in terms of specification and contract maturity.

Hedges for spot price volatility existed in the PNW in the form of bilateral forward futures, OTC forward contracts and self-build options. Buyers that wanted to hedge in the PNW could have done so. Exh. IE-2 at 14. NPG witness Ms. Stegeman stated the truism that if options were bought at an unduly high price they might not be beneficial. Exh. NPG-57 at 4. However, Ms Stegeman also agreed that every traditional tool that load-serving entities use to hedge against the risk of variability of price in the spot market, was available throughout the PNW market during the period December 25, 2000 through June 20, 2001. Tr. at 656-657. California Parties' witness Dr. Pechman attempted—without explanation or proof—to dismiss hedging strategies as "nascent economic instruments," Exh. CAL-14 at 15, but on cross-examination he admitted that hedging products had been available for decades. Tr. at 1033:13-25. Options do, of course, have a cost. Nonetheless, they are a useful tool in reducing exposure to price risk, particularly in volatile markets, such as the PNW spot market during the relevant period. The refund claimants simply elected to forego these means and others to protect themselves from price increases in the spot market. On examination by his own

counsel, Port of Seattle witness Holbrook conceded that: "prior to the energy crisis, we probably could have entered into a hedging contract for less than what we're paying today." Tr. at 627:12-627:19.

As described above, the increase in market prices that began in the late Spring of 2000 reflected market fundamentals—increasing demand at a time of significantly reduced supply. Of course, these higher prices were not initially troublesome to the refund claimants, because power flows in the summer from the PNW to California. Only when higher prices persisted into the Fall did they become an issue for the PNW refund proponents, because that is when flows traditionally reverse so that power flows from California to the PNW. Exh. ENR-1 at 7-8.

TFG further avers that the refund claimants contend that they cannot be expected to have foreseen the market forces that led to the volatility of the spot market during the relevant period. This claim is contrary to the evidence, including the testimony of the claimants' own witnesses. For example, Ms. Stegeman's testimony notes the first price spike came in May 2000, natural gas prices started rising in the Summer of 2000, and the Mid-C firm peak index in June was as high as $672.88/MWh. Exh. NPG-16 at 15. Seattle City Light's witness Mr. McCullough similarly testified that high prices began in May of 2000. Exh. NPG-68 at 6, 11.

The evidence proves that in the Summer of 2000 Seattle and Tacoma, who were then selling wholesale power into the spot market, had noticed that spot market prices were becoming more volatile, at least in part due to supply shortfalls. Another witness supporting refunds, Mr. Hart, testified that "in the summer of 2000, CERS might have been able to

secure reasonably priced forward block bilateral arrangements for the Winter and Spring of 2001" had it been in existence then. Exh. CAL-9 at 3. Such forward contracts were available in the marketplace at this time, and Seattle and Tacoma could have increased their forward purchases instead of increasing their reliance on the spot market, TFG maintains.

In short, TFG asserts, the perceived flaws in market structure that led the Commission to direct refunds in the California proceeding are not present here. Moreover, the cure that the Commission prescribed for California is a large forward market and a wide variety of products from which buyers can assemble balanced portfolios that hedge against both delivery and price risks.[168] Precisely these attributes have at all times, including the period at issue here, characterized the PNW market. Rather, refund claimants seek to have the Commission reimburse them for their voluntary choices in a market that offered them many alternatives.

TFG argues that in authorizing sales of power at market-based rates, the Commission has concluded that prices negotiated between sellers and buyers, in the absence of market power, are just and reasonable and, therefore, "lawful." In fact, important public policy considerations have necessitated development of a competitive wholesale electric market over the last decade.

As the United States Supreme Court has noted, "the history of Part II of the Federal Power Act indi-

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[168] *See, e.g., San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services into Markets Operated by the California Indep. Sys. Operator and the California Power Exchange*, 92 FERC ¶ 61,172, at pp. 61,607-8 (2000); December 15 Order, 93 FERC at pp. 61,981-82, 61,995, 61,999.

cates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."[169] In response, the Commission for over a decade has consistently sought to foster the development of the competitive wholesale electric market.[170] In unleashing competitive market forces, the Commission attempted to create a structure that would send timely and accurate price signals to both the supply and demand sides of the market. The Commission's goal was to provide reliable supplies of electricity at the lowest cost to U.S. consumers over the long run.[171] Implicit was the knowledge that prices will fluctuate in a competitive market, at times to extreme levels. Explicit was the belief that, in the long run, lower costs and greater efficiencies would be achieved to the benefit of all.[172]

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[169] *Otter Tail Power Co. v. U.S.*, 401 U.S. 366, 374 (1973); *see also Public Sys. v. FERC*, 606 F.2d 973, 982 (1979) ("On numerous occasions the Supreme Court has recognized the importance of competition in regulated industries and the responsibility of regulatory agencies to encourage competitive forces.").

[170] Order No. 888 at pp. 31,639-52. In moving away from a heavily regulated cost-of-service regime for wholesale power sales, the Commission, often citing Congressional intent, found that: costs of electric supply were higher than necessary; regulated prices created distorted market signals; stranded costs had been incurred, further distorting market signals; there existed a utility-by-utility, region-by-region disparity of prices; economic and environmental efficiency were not being maximized; and, new technologies developed best under competitive conditions and their development needed to be encouraged. *Id.*; *see also Pub. Svc. Co. of Indiana*, 49 FERC ¶ 61,346, at pp. 62,445-46 (1989).

[171] *Pub. Svc. Co. of Indiana*, 49 FERC at p. 62,243.

[172] *Pacific Gas & Elec. Co.*, 38 FERC ¶ 61,242 at p. 61,792 (1987) ("It is on the basis of efficiency, and the likelihood that increased efficiency will result in lower prices to consumers,

According to TFG, it is not, therefore, exaggeration to say that the primary public policy goal of the Commission over the last decade has been to foster and protect the development of a wholesale competitive electric market. That goal has not changed despite events in California. In its April 26 Order, the Commission lists certain design principles to guide the development of any market mitigation plan for California:

> [B]uyers and sellers need to know the rules up front and have confidence that those rules will not be subject to constant change or interpretation; prices should be mitigated before they are charged, not after; price mitigation should be as surgical (least intrusive) as possible and last for as little time as possible; price mitigation should be as market oriented as possible and adopt market solutions and mechanisms to the maximum extent possible; the pricing provisions must encourage, and not discourage, the critically needed investment in infrastructure (*e.g.*, increasing generation supply, adding required transmission, and implementing demand response).[173]

The TFG submits that these same principles should form the basis for any decision in this case.

TFG avers that there is nothing in the market structure of the PNW which is anti-competitive or which needs to be "corrected." Most of the power is traded in the forward markets, and only a small percentage of the transactions occur in the daily

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that we shall approve the [market-based] rates in the WSPP as just and reasonable.").

[173] 95 FERC at p. 61,352.

balancing, highly volatile spot market[174]—precisely the model the Commission supports in its orders concerning the California market. The Commission should be most concerned not to destroy the functioning of the PNW markets while it works to remedy what it has determined to be flaws in the California structure.

TFG further maintains that the refunds proponents retreat to cost-of-service pricing or production costs as the basis for their proposed refund determinations. This course is ill-advised and would mangle market price signals. *See* Section IV.C.2 *supra*. It is also at war with the Commission's efforts to nurture the development of competitive market forces. The Commission itself has rejected this approach:

> We reject proposals to return to cost based regulation. . . [P]rices based upon traditional cost of service are incompatible with fostering a competitive market. As we stated in the November 1 Order, traditional cost-based pricing reflects the cost of the asset without any regard to market conditions. The one thing California needs most is new supply and a return to traditional cost of service will not encourage supply to enter the California market.[175]

Further:

> Several commenters suggest that the commission require marginal cost based bids . . . We reject these proposals for numerous reasons . . . In the absence of a capacity market, as is the case in California, if a seller only has peaking units, it would only receive the variable cost of energy and

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[174] Exh PWX-12 at 5:14-17, 9:6-7.

[175] December 15 Order, 93 FERC at p. 62,008.

> no payment for its fixed cost. Sellers could not stay in business long with that revenue stream.[176]

And finally:

> Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs . . .[177]

Absent compelling reasons to reset prices charged between willing buyers and willing sellers, market pricing should continue to establish just and reasonable rates for the wholesale spot market in the PNW.[178] It is particularly important in this regard that sellers be able to recover the costs of the power that they purchased in the market from third parties. Analysis of any price cap should rest, not on the level of prices in a small portion of the PNW market over a short period of time, but rather on the market structure that produced those prices and rapidly readjusted.

TFG further contends that the record proves that the PNW market, with a long history of trading with multiple buyers, sellers and products, was working in a competitive manner. Tacoma witness Ms. Stegeman admitted that she had no challenge to the conduct of any particular party selling power in the

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[176] *Id.* at pp. 62,008-9.

[177] Order 888 at pp. 33,061-62.

[178] As will be demonstrated in the ensuing sections, the claimants and the Commission bear a heavy burden of proof to retroactively change prices which have already been determined just and reasonable.

PNW. Tr. at 659. Seattle witness Mr. McCullough stated in his rebuttal testimony that: "The Pacific Northwest market over this time period was a price taker," which means that no entity in the region was able to exercise market power. Other expert witnesses admitted that they had no evidence of market power in the PNW. Philip Movish, witness for Tacoma, Port of Seattle, and Northern Wasco, admitted that there were a substantial number of sellers in the region, particularly in this time period. Tr. at 727. He also admitted that he had not studied how many vendors of wholesale power it would take to ensure a competitive market. Tr. at 732-33. Witness for the California Parties, Dr. Carl Pechman, admitted that he had not provided an economic analysis of demand elasticity in his testimony. Tr. at 1030. Further, he admitted that he had not provided any evidence of "joint action," by PNW power suppliers. Tr. at 1030.

In sum, TFG argues, there is not even one specific allegation in the entire record of the existence or exercise of market power or violation of any tariff or agreement.

2a. What Was The Volume Of Spot Market Bilateral Sales Transactions In The Pacific Northwest For The Period December 25, 2000 Through June 20, 2001?

2b. What Were The Price And Terms And Conditions Of The Sales Contracts For Spot Market Bilateral Sales Transactions In The Pacific Northwest For The Period December 25, 2000 Through June 20, 2001?

2c. Who Were The Net Sellers And Net Buyers Of Electric Energy In Spot Market Bilateral Sales Transactions In The Pacific Northwest

For The Period December 25, 2000 Through June 20, 2001?

NPG

Data regarding the three above issues, *i.e.*, the volume of sales transactions, the prices, terms, and conditions of sale, and the identity of net sellers and net buyers has been submitted by many, but not all, Pacific Northwest market participants in the form of responses to a data template prepared by Commission staff and adopted by the Presiding Judge, NPG maintains. This information has been submitted *in camera* and has not been available for use by any other than the party submitting the data.

NPG argues it can neither verify nor validate whether the sellers submitted data sufficient for the Commission to determine the price, terms and conditions of every spot market sales transaction in the Pacific Northwest from December 25, 2000 through June 20, 2001. Pursuant to the August 9 and 13 Orders in this proceeding, data was submitted to the Presiding Judge and to Commission staff under seal. Such data is not available for public review. Thus, the sellers' identities, and the reported prices, terms and conditions of spot market sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001, have not been tested by counterparties to those transactions—the purchasers who paid the unjust and unreasonable prices. The Commission itself must examine the sealed data submissions in this proceeding to determine the prices and terms and conditions of the spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001.

California Parties

California Parties contend that the confidential template data assembled by Commission Staff, based on submissions from all transaction participants, will provide the total volume of spot market bilateral sales transactions in the PNW for the period December 25, 2000 through June 20, 2001. The California Parties have answered the same question concerning transactions involving CERS through evidence at hearing.

In the PNW, CERS purchased a total volume of 6,803,549 MW/h during the refund period, at a cost of $2,638,589,077, for an average cost of $388 per MW/h. (CAL-11). In addition, CERS engaged in exchanges in the amount of 584,725 MW/h. (CAL-12). Finally, CERS made sales during the refund period in the amount of 67,117 MW/h, for which it charged $1,606,689 (i.e., an average sales rate of $24 MW/h). (CAL-13).

According to the California Parties, during the refund period, CERS purchased 1,942,581 MW/h from Powerex on a 24 hour-or-less basis at a total cost of $898,267,499, for an average rate of $462 MW/h. (CAL-11). Powerex contends that virtually all of these 24 hour-or-less sales must be excluded for refund purposes because they do not constitute "spot market" sales. (Peterson, PWX-6 at 11:2-4). Powerex's theory for exclusion is that these sales were made under a "capacity-backed fixed-price arrangement" that was negotiated between Powerex and CERS "at the most senior level." (Peterson, PWX-6 at 10-11). The facts do not support this claim, California Parties argue. During the refund period, CERS made a series of purchases from Powerex of 24 hours or less in duration on a last-resort basis, and

Powerex charged whatever it wanted to charge for the power—often $500 MW/h—because it was able to do so.[179] In a bilateral market, all of the transaction prices were based upon the offers made by sellers. Moreover, as California Parties' Witness Hart explained on rebuttal, there was no "contract" to provide variable quantities at a fixed price; this was a series of transactions entered on a daily or hourly basis at whatever price Powerex demanded. (CAL-9 at 4:13-21).

California Parties contend that nowhere in the testimony of Powerex's witnesses or on cross-examination was Powerex able to elicit any evidence that confirms an agreement between Powerex and CERS that sales by Powerex would be either "capacity-backed" or "fixed-price." Powerex has produced no agreement that either (1) obligated Powerex to sell any particular quantities to CERS at any particular price, or even to stand ready to do so, or (2) obligated CERS to purchase particular quantities or to purchase quantities on demand at a particular price. The only written agreements produced by Powerex, TFG-17 and 18, were created for the sole purpose of modifying the standard WSPP purchase agreement[180] credit and payment terms. Those modifications essentially provided that, in the event Powerex and CERS

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[179] Witness Hart explained on cross-examination: "Basically . . . Powerex unilaterally set its prices on any given moment of every day, and periodically I would call them saying look, you guys continue to charge us prices that are way out of the market. You need to bring them down. . . . I continually asked them for forward purchase contracts. I never got them. All I ever got was spot purchases at the price they dictated." (Tr. 897:17-25-898:1).

[180] Exhibit 6.

happened to enter into bilateral transactions during the specified time periods, special (i.e., far more stringent) credit and payment terms would apply. The *only* reference to price or volumes in TFG-17 and 18 is a *disclaimer* concerning those items—a representation that the agreements specifically do *not* address price and volumes, and that any arrangements concerning price and volumes must be made "in the normal course" pursuant to verbal confirmations between the respective trading personnel of Powerex and CERS.[181] For all of the transactions at issue that Powerex seeks to exclude, these verbal confirmations "confirmed" a transaction of 24 hours or less.[182]

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[181] Thus, Preamble Paragraph D of TFG-17 provides:

> Powerex and CDWR also understand and intend that **verbal confirmations as to price and volumes will be made in the normal course between** their respective trading personnel and that this Confirmation Agreement will apply to such transactions and that **no obligation to deliver energy arises hereunder other than pursuant to such verbal confirmations**.

TFG-17: 2 (emphasis added). An identical provision is contained in TFG-18, Preamble Paragraph D:1.

[182] If Powerex were correct that it had a long-term "capacity-backed" "fixed-price" contract with CERS, the WSPP Purchase Agreement would have required the terms to be set forth in writing in a Confirmation Agreement. Section 32.1 of the WSPP Agreement specifies that: "Written confirmation shall be required for all transactions of one week or more." According to Powerex, its "capacity-backed" "fixed-price" agreement with CERS was in place from January 17, 2001 through June 20, 2001, yet, in violation of Section 32.1 of the WSPP Agreement, neither of these alleged essential terms was ever confirmed in writing. This is further evidence that no such agreement existed.

The testimony of the TFG experts on the definition of "spot market" transactions is singularly unhelpful to Powerex on this issue, California Parties maintain. Mr. Adamson, for example, identified the key concept in spot market transactions as "immediacy." (ENR-25 at 4-5). Plainly, CERS' purchases from Powerex on a daily and hourly basis were "immediate" within Mr. Adamson's definition. Recognizing the possibility of sales by Powerex to CERS, the parties agreed in TFG-17 and 18, at the insistence of Powerex, to modify the WSPP credit and payment arrangements that otherwise would govern transactions of 24 hours or less. The sales themselves, however, occurred on a purely last-minute 24 hours-or-less basis at whatever price Powerex dictated.

Similarly, TFG Witness Van Vactor highlighted as a hallmark of spot market transactions that there be no obligation or implied intent to continue to sell in subsequent periods. (ENR-23 at 4:18-19). Applied here, this criterion necessarily results in a determination that Powerex's sales to CERS were spot market transactions within Mr. Van Vactor's definition: as set forth in TFG-17 and 18, Powerex had no obligation to CERS beyond the day-to-day verbal confirmations between traders. Moreover, as explained by Mr. Hart, CERS did not purchase from Powerex on a daily basis unless it had no other choice.[183]

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[183] As Mr. Hart explained in his testimony:

> Indeed, our purchases from Powerex were usually our last purchases, because Powerex's price was usually the highest. It was Powerex's choice to sell to us in this last minute fashion, and there is no useful distinction between the types of transactions we entered into with Powerex, and all of the other sport market transactions in which CERS engaged,

Powerex's own expert, Dr. Tabors, offered no credible support for Powerex's claim on this point. As revealed in both his rebuttal testimony (PWX-12 at 8) and in cross-examination (Tr. 993-994), Dr. Tabors relied exclusively on characterizations about the so-called arrangement provided to him by Powerex's Witnesses Peterson and Yazdi. Dr. Tabors was unable to offer any independent assessment of whether the vast number of daily transactions that Powerex seeks to exclude were spot market transactions or otherwise.[184] Attempting to offer "circumstantial" evidence of a fixed-price agreement between Powerex and CERS for purchases at $500 MW/h, Powerex enlisted Dr. Tabors to graph the pricing of the transactions between Powerex and CERS during the refund period. (TFG-20). Notwithstanding the numerous errors of omission and inclusion,[185] the graph, how-

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except that we generally had to pay a lot more to Powerex under extreme payment schedules to satisfy credit concerns.

(CAL-9 at 4:19-5:2).

[184] As Dr. Tabors testified on cross-examination:

Q. Now, you referred to the agreement between Powerex and CERS. There isn't any agreement, is there? There's no contract?

A. There's an agreement that was referenced in other testimony, not mine.

Q. Have you seen the contract that you're referring to now, the contract that you said was for a fixed price agreement . . . ?

A. Have I seen that? No, sir.

Tr. 993:23-994:4.

[185] Data in Mr. Green's work papers (TFG-19) that does not appear to be reflected on TFG-20 includes the following: 3/12/01 ($370); 5/2/01 ($194); 5/4/01 ($105); 5/5/01 ($105); 5/18/01 ($84); 5/19/01 ($84); 5/30/01 ($69); 6/1/01 ($111); 6/2/01 ($111); 6/3/01 ($135); and 6/5/01 ($81).

ever, reveals nothing more than the fact that CERS paid Powerex the exorbitant price of $500 MW/h for numerous individual transactions of 24 hours or less during the refund period.[186]

Even less helpful to Powerex on this issue is a Commission Staff Report used by TFG in an attempt to impeach Commission Staff Witness Tingle-Stewart, wherein Commission Staff defined a "forward" contract (i.e., the type of contract that Powerex claims it had with CERS) as one in which the buyer "is obligated to take delivery" and the seller is "obligated to provide delivery" of a "fixed amount of a commodity" at a "predetermined price" on a "specified future

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Data points on TFG-20 that do not appear in Mr. Green's underlying work papers (TFG-19) include the following: 1/17/01 ($600); 1/17/01 ($480); 1/17/01 ($445); 3/12/01 ($340); 3/26/01 ($375); 3/26/01 ($250); 3/26/01 ($100); 4/12/01 ($0); 5/4/01 ($194); 5/5/01 ($194); 5/5/01 ($175); 5/6/01 ($194); 5/19/01 ($0); 5/21/01 ($0); 6/15/01 ($325); 6/16/01 (290); 6/17/01 ($500); and 6/17/01 ($450).

Given that Dr. Tabors "checked this data over a number of times" (Tr. 993:10), the sheer quantity of errors raises legitimate concerns about the reliability of Dr. Tabors' testimony generally.

[186] TFG-20 purports to be a graphic depiction of Mr. Green's work papers introduced into the record by Powerex as TFG-19. As a comparison between those work papers in TFG-19 and Dr. Tabors' graph demonstrates, there are numerous dates on which the graph reports the price charged as $500 MW/h, but the actual price reported in the work papers was not $500 MW/h: 1/25/01 ($498); 1/26/01 ($498); 2/13/01 ($497); 2/14/01 ($497); 2/15/01 ($497); 2/16/01 ($497); 2/17/01 ($497); 2/18/01 ($497); 2/19/01 ($497); 2/20/01 ($497); 2/21/01 ($497); 2/22/01 ($497); 2/23/01 ($397); 2/26/01 ($497); and 2/27/01 ($497).

date."[187] The alleged "forward" agreement between Powerex and CERS fails each of these specific tests.[188]

In summary, according to the California Parties, the numerous daily and hourly transactions between Powerex and CERS during the refund period are precisely what they appear to be—daily and hourly transactions that qualify as "spot market" transactions under even the most narrow definition of that term as advocated by Powerex and the other TFG group members.[189] The facts indicate that Powerex exercised raw economic power over CERS in a series of hourly and daily transactions. There was no contract. Powerex did not offer a "unique product"

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[187] TFG-26 (Staff Report dated September 22, 1998, Section G-2, definition of "forward contract").

[188] Powerex suggested on cross-examination that its sales to CERS constituted a "forward contract" (*i.e.*, in its view something other than an includable spot market contract) because Section 35 of the WSPP agreement provides that transactions under the WSPP Agreement are "forward contracts" for purposes of the United States Bankruptcy Code. (Tr. 889:8-891:6). Not so. For Bankruptcy Code purposes, the "forward contract" designation simply means that various Bankruptcy Code provisions that could otherwise disrupt commodities markets, such as the automatic stay and the trustee's avoidance powers, do not apply. 3 Collier on Bankruptcy (15th Ed.). ¶ 362.05[6]. The WSPP Agreement's incorporation of this Bankruptcy Code protective device obviously does not transform transactions that are one hour real time spot market sales into long-term forward contracts.

[189] Of course, if one of the broader definitions of "spot market" advocated either by the claimants or by Commission Staff is adopted, all of the transactions in question that Powerex erroneously attempts to characterize as "forward" transactions nonetheless would be included as "spot market" transactions, because they occurred over a period of less than a year (indeed, approximately 5 months).

based on high-level negotiations. (Yazdi, PWX-7A at 7:6-10). CERS bought from Powerex on a daily and hourly basis (but only what it needed to buy after exhausting other lower-cost sources), and paid whatever Powerex demanded. As California Parties' Witness Hart explained, CERS would have preferred a forward contract with Powerex, but Powerex consistently refused to enter into such an arrangement (CAL-9 at 4:1-5; Tr. 897:17-898:1).

Certain parties, including BPA and Powerex, maintain that where the seller acted merely as an intermediary or agent for the buyer in purchasing power from other sellers and reselling to CERS, such transactions must be excluded from the refund calculation. (Oliver Direct, BPA-1 at 13-14; Yazdi, PWX-7A at 9-10). BPA refers to these types of transactions as "sleeve" transactions, whereas Powerex refers to them as "aggregation service." Both argue, for different reasons, that these types of transactions are not includable spot market bilateral transactions. Neither is correct.

With respect to the "sleeve" transactions described by BPA, the reasons given for exclusion are purely equitable in nature, in that they focus on the motivation for the transaction and the margin (or lack thereof) earned by BPA. (Oliver Direct, BPA-1 at 13-14). The California Parties acknowledge that equitable considerations may be germane to a determination of whether a refund is appropriate. Analytically, however, equitable considerations have nothing to do with whether a particular transaction is includable as a spot market bilateral sales transaction in this proceeding. In the "sleeve" transactions discussed by BPA, BPA indisputably is the seller of record. Assuming that the transactions otherwise qualify as

spot market transactions—and BPA does not allege otherwise—they cannot be excluded merely because BPA may have undertaken the transaction to assist CERS at minimal compensation, as BPA claims.

With respect to the "aggregation service" provided by Powerex, the same analytical approach compels the conclusion that the transactions should be included as spot market bilateral transactions, so long as they otherwise qualify as such. Powerex argues that they do not so qualify, because Powerex made these sales as part of a "continuing arrangement." (Yazdi, PWX-7A at 10:4-7). As with its alleged "capacity-backed fixed-price" contract discussed above, Powerex offers no proof of a "continuing arrangement" as to these transactions. As explained by California Parties' Witness Hart, these were *daily* transactions in which Powerex acted as a marketer for profit.[190] On the present record, there is no basis for excluding either BPA's "sleeve" transactions or Powerex's "aggregation service" transactions. Both parties were the sellers of record in these transactions. The transactions occurred on an hourly or daily basis, so they qualify as "spot market" transactions under even the

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[190] As Mr. Hart explained in rebuttal:

> Beginning in early May of 2001, CERS used Powerex as an aggregator for daily purchases at the mid-Columbia hub for delivery to the California-Oregon Border ("COB") and the Nevada-Oregon Border ("NOB"). Powerex essentially acted as a marketer in these daily transactions, and charged the mid-Columbia index price plus a percentage mark-up determined by Powerex. Powerex then was responsible for all transmission charges and losses incurred in transporting the power to CERS. Powerex insisted on doing this in order to give CERS firm energy delivered at a point and price. It was no different from any other short term transaction.
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> (CAL-9 at 8:12-19).

most narrow definition advocated by TFG. Neither party has provided a rational or credible basis for treating the transactions as other than spot market bilateral transactions.[191]

During the refund period, CERS entered into exchange transactions with BPA and Powerex, for a total volume of 584,725 MW/h. (CAL-12). A typical exchange, the sending and receiving of products, is one in which one party, such as CERS, sends energy to a counter-party before Summer for return during the Summer. (Green Direct, CAL-1 at 5:1-3). In the Order on Format for Data Submission,[192] parties were invited to treat exchange transactions as transactions subject to refund and to submit relevant data.

BPA attacks the basic theory of including exchanges, arguing that the transactions do not involve a dollar per MW/h rate. (Oliver Direct, BPA-1 at 16:3-6). As California Parties' Witness Green explained on rebuttal, however, exchange transactions are appropriate for inclusion because they were a substitute for purchases, at an exchange rate that produced a MW/h value significantly higher than a reasonable purchase price. (CAL-10 at 8:23 - 9:2), the California Parties argue.

According to the California Parties, Powerex argues that the two exchange transactions in which

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[191] The same rationale applies to IDACORP witness Ciccheti's claim that marketers should not be required to pay refunds. (IE-2 at 26). If a marketer is the seller of record, the transaction must be includable for refund purposes, just as any other seller's transaction is included.

[192] Order on Format for Data Submissions, issued August 9, 2001, slip op. at 10 ("There will not be an exchange template. Parties claiming a refund for an exchange transaction shall file the relevant data for the transaction, specifying this fact.").

it engaged with CERS should be excluded because (1) they are seasonal in nature and thus have no nexus to spot market transactions, and (2) the "returns" by Powerex of energy provided by CERS to Powerex during the refund period will not occur until after the close of the refund period. (Yazdi, PWX-7A at 12:1-5; Tr. 939-940). Neither argument has merit. The first argument—concerning the seasonal nature of exchanges—precludes recovery only if Your Honor and the Commission adopt the extremely narrow "24 hours or less" definition of "spot market" urged by Powerex and the other TFG group members.[193] As for Powerex's second objection—that the redelivery period falls outside of the refund period—the short answer is the one provided by Mr. Green on cross-examination: CERS performed its part of the bargain —that is, it already "paid" by providing power to Powerex—during the refund period; when Powerex returns the power, it should do so at a reasonable (i.e., mitigated) equivalent price. (Tr. 939-940).

The California Parties—the AG, the PUC and the EOB—are seeking refunds in this case on behalf of California ratepayers for whom CERS purchased power during the refund period. CERS was required to pay exorbitant rates for power during the refund period, in order to meet the energy needs of California consumers, and California consumers will continue to bear the brunt of those high prices. CERS, a

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[193] Even this argument does not apply to power delivered by CERS to Powerex during the period May 18-May 21. *See* TFG-22. That time period encompassed a Friday and a three day weekend (May 21, 2001 was a Canadian holiday), and therefore fits within even TFG's definition that includes the Pacific Northwest "24 hours or less" spot market weekend convention. (*See, e.g.*, Tr. 903:16 - 904: 3).

net buyer of electric energy in the PNW during the refund period, has not asserted a refund claim on its own behalf that is separate from the claim presented by the California Parties. Rather, the refund claim associated with CERS' refund period purchases, the proceeds of which, under California law, will be flowed back to California's consumers, is being asserted by the California Parties, the lawful representatives of California's retail ratepayers. The California Parties have standing to assert the refund claim of retail ratepayers associated with CERS' purchases on behalf of those ratepayers. The FPA specifically authorizes the Commission to admit as a party in a proceeding "any representative of interested consumers."[194] Interpreting a similar provision in the Natural Gas Act, the D.C. Circuit explained that the consumer representative in such situations need not have the interest of a direct purchaser, but instead relies on the interest of the state in protecting its citizens—that is, the state's *parens patriae* interest.[195] Similarly, the Commission traditionally has permitted state consumer representatives automatic party status in proceedings,[196] and has permitted states' attorneys

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[194] Section 308 of the FPA, 16 U.S.C. § 825g(a).

[195] *Maryland People's Counsel v. FERC*, 760 F.2d 318, 321 (D.C. Circ. 1985) ("It seems to us inconceivable that the specific provision of party . . . status for states and state agencies envisioned that these entities would be particularly likely purchasers of natural gas; to the contrary, it was evidently designed to recognize precisely the interest of the states in protecting their citizens in this traditional governmental field of utility regulation—that is, the states' *parens patriae* interest.").

[196] 18 C.F.R. § 385.214(a)(2) ("Any State Commission is a party to any proceeding upon filing a notice of intervention in that proceeding, if the notice is filed within the period established under Rule 210(b)").

general, state commissions and other state agencies that represent consumer interests standing to litigate wholesale rate issues.[197]

Importantly, the California Parties maintain, in recognizing the standing of state agencies to litigate wholesale rates, the Commission has made it quite clear that the indirect claim of a state agency on behalf of retail consumers is distinct from and not in any way dependent upon the participation or non-participation of the direct purchasers who serve those same end user retail customers. Thus, in *United Gas Pipe Line Co.*,[198] the Commission held that state agencies were permitted to pursue litigation on behalf of indirect consumer interests, even though the local gas distribution company--the actual direct purchaser—chose not to do so: The Commission recognizes that as a matter of policy LDCs should be able to make their own business judgments and incur the cost consequences that result. LDCs may not want to litigate, and the Commission under Order No. 500 generally discourages litigation. However, it also must be recognized that state regulatory agencies have legitimate interests in having an opportu-

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[197] *Williams Gas Pipelines Central, Inc.*, 94 FERC ¶ 61,285 (2001) (Missouri Public Service Commission permitted to intervene in enforcement action under Natural Gas Act because pipeline was major supplier of natural gas transmission and storage service to Missouri customers, and Missouri Public Service Commission, as public representative of retail consumers in Missouri, was permitted to intervene); *New England Power Co.*, 51 FERC ¶ 61,219 (1990) (Attorney General of Commonwealth of Massachusetts and New Hampshire Public Utilities Commission permitted to intervene out of time in electric rate proceeding, given, *inter alia*, "the interests of the constituencies they represent. . . .").

[198] 45 FERC ¶ 61,335 (1988).

nity to litigate the wholesale rates. In weighing these interests, the Commission chose to recognize the state agencies' interest in being able to litigate. *This is consistent with our long standing practice of recognizing the standing of state agencies to litigate wholesale rates.*[199]

The essential teaching of *United Gas Pipe Line*, therefore, is that state consumer representatives may pursue an indirect claim on behalf of consumers (and may be the party best suited to do so) even though the direct purchaser from the regulated seller chooses not to pursue a claim. Each of the California Parties—the AG,[200] the PUC,[201] and the EOB,[202]—has authority under California law to act on behalf of California's retail ratepayers. Any refunds awarded in this case associated with CERS' purchases on behalf of California's retail end use customers will, as

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[199] 45 FERC ¶ 61,335, at p. 62,054 (emphasis supplied).

[200] Under the California Constitution and the California Government Code, the Attorney General is authorized to safeguard the public interest, which includes the authority to represent the interests of California's retail end use customers, who are entitled to refunds associated with wholesale electric power purchases made by CERS on their behalf. Cal.Const. art. V, § 13; Cal.Govt.Code § 12511.

[201] The California Public Utilities Commission is a constitutionally-established agency with the statutory mandate to represent the interests of natural gas and electric consumers throughout California in proceedings before this Commission. Cal.Pub.Util.Code § 307. In addition, the CPUC is directed to "participate fully in all proceedings before this Commission in connection with" electric restructuring in California. Cal.Pub. Util.Code § 365.

[202] The Electricity Oversight Board is authorized by statute to represent the state of California and its citizens in litigation before this Commission. Cal.Pub.Util.Code § 341.

a matter of California law, accrue to the benefit of retail ratepayers. CERS operates under the provisions of ABX1-1, enacted February 1, 2001.[203] Among other things, the statute establishes the Department of Water Resources Electric Power Fund, and requires that all revenues payable to CERS under the statute be deposited in that Fund. CERS may sell power acquired under the statute to retail end use customers, *at not more than its acquisition costs*, including related costs of transmission, scheduling, etc. Payments from the fund may be made only for purposes authorized by the statute. Accordingly, any refunds paid to CERS will be deposited in the first instance in the Electric Power Fund, but then will flow back to retail end use customers in order to satisfy the statute's requirement that CERS charge those end use customers no more than its acquisition costs for power going to the retail end user less costs.

According to the California Parties, the Commission has determined in a series of recent orders in this and the *San Diego* proceeding, that it may exercise conditional authority over municipal utilities and other public power entities (collectively, "non-public utilities"), and that it may order refunds to be paid by non-public utilities. In addition, the Commission clearly set the scope of this proceeding to determine issues related to *all* sales made in the PNW, with no exemption for sales made by non-public utilities.

Non-Jurisdictional Utilities

Non-jurisdictional municipal utilities have asserted throughout this proceeding that it is unlawful to

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[203] AB1x-1 added Division 27 to the California Water Code, §§ 80000-80270. This statute was introduced into the record in this case as TFG-14.

order refunds related to the bilateral power sales of non-public utilities in the Pacific Northwest for the period in question. According to these entities, the jurisdictional reasoning that underlies the assertion of refund authority over power sales of non-public utilities to the California Independent System Operator and Power Exchange markets in the Commission's Order of July 25, in Docket No. EL00-95, *et al.*, may not extend to the bilateral power sales of non-public utilities in the Pacific Northwest market for the bilateral power sales of non-public utilities in the Pacific Northwest market for the period in question in this proceeding. A centralized single clearing price auction that sets wholesale prices for both public utilities and non-public utilities, pursuant to market rules set by this Commission and administered by public utilities subject to the Commission's jurisdiction (the California ISO and PX) were the reasons for extending refund authority to certain non-jurisdictional entities that have sold power to the California ISO and PX. These entities argue that the record evidence in this proceeding shows that the circumstances in the Pacific Northwest bear no resemblance to the sales in the California ISO/PX. For instance, the sales at issue were made pursuant to bilateral contracts voluntarily entered into between willing buyers and willing sellers. The Pacific Northwest operates as a true commodity market where prices are set by bilateral negotiation, rather than administered by a separate authority. Ex. NPG-1 at 7, 11. The Northwest market is largely the product of the existence of the regional non-jurisdictional transmission system and the Northwest's hydroelectric generation base. In addition, these entities maintain the WSPP Agreement specifically states

that it does not provide a basis for exercise of Commission jurisdiction over the power sales of utilities such as Municipal Systems and the Commission has stated that it lacks jurisdiction over the bilateral sales of non-jurisdictional entities under the WSPP. *Citing Western Systems Power Pool*, 55 FERC ¶ 61,495, at p. 62,713 (1991). The municipal entities further contend that the Commission has no jurisdiction under Section 205 and 206 of the FPA over the power sales of utilities such as municipal systems. *Citing Mid-Continent Area Power Pool* ("MAPP") 89 FERC ¶ 61,135 (1999), *reh'g denied*, 92 FERC ¶ 61,229 (2000); *New West Energy Corporation*, 83 FERC ¶ 61,004 (1998).

TFG

TFG avers that volumetric data has been submitted to the Presiding Judge and Staff under confidential seal.[204] Nonetheless it is clear that spot market

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[204] The statistical data sought was submitted to the ALJ on a confidential basis and presumably will be certified to the Commission. Staff witness Poffenberger, however, provided a glimpse into the breadth and informational value of those submissions and, in the process, underscored numerous problems with this data gathering effort (Exh. S-3 at 6:3-19; Exh. PWX-12 at 2):

- Only 56 of the 220 entities that belong to the WSPP submitted data.
- None of the parties proposing refunds in this case, provided the date and hour when each transaction was entered into. (As noted by Dr. Tabors, Exh. PWX-12 at 3 n.1, and pursuant to the Stipulation entered during the hearing, EWEB does not appear to be seeking affirmative relief, but it did provide dates and hours.)
- The data submitted fails to reveal whether the power purchased was used to serve retail load in the Pacific Northwest or whether is was resold, possibly into California. (Testimony

bilateral sales transactions constituted only a small percentage of the total volume of transactions in the region because forward contracts were heavily relied upon.

Spot market bilateral sales in the PNW took place under diverse prices, terms and conditions, TFG contends. Certain of this information is contained in the confidential data submission.[205]

Moreover, TFG argues most market participants were both buyers and sellers, often in multiple "ripple" transactions. Calculations to determine net positions were not possible, given the available information, time and procedures.[206] Kaiser and Bonneville argue that sales made by Bonneville for Kaiser cannot be undone due to the inequities of ordering the aluminum company to refund money.

Staff

According to Staff, in the July 25 order, the Commission noted the "complexities associated with these retroactive bilateral calculations" and established a separate preliminary evidentiary proceeding to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the PNW for the period

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indicates, however, that this information in fact is available. Exh. PGE-1 at 3:4-4:2.)

• Sellers that submitted data were unable to identify upstream vendors and it is therefore impossible to fully assess the potential magnitude of so-called "ripple" claims.

What is clear is that the refund claimants represent an extraordinarily small segment of the Pacific Northwest market.

[205] *See id.*

[206] *See id.*

beginning December 25, 2000 through June 20, 2001. The Commission stated that:

> The record should establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. This will help the Commission to determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest.[207]

The Commission required the parties to provide this data to the Presiding Judge no later than 15 days after the first prehearing conference.

At the prehearing conference on August 1, 2001, the parties agreed to submit data on a generic template to be drafted by the Staff.[208] Following Staff's filing of a proposed template and the parties' comments, the Presiding Judge issued orders adopting a template and ordered all parties in the proceeding to provide data.[209] *See* Ex. S-5.[210] The template

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[207] 96 FERC at p. 61,520.

[208] On August 3, 2001, Staff submitted its recommended format for reporting hourly sales into the PNW.

[209] "Order on Format for Data Submissions" issued August 9, 2001 and "Order on Motions for Clarification and Request for Modification" issued August 13, 2001.

[210] The template includes columns for: (1) the date and hour that sales begin and end, and the date and hour that the sales transaction was entered into; (2) Upstream Vendor, the Seller's source of supply (purchase or generation) used to make the sale; (3) the name of the Buyer who is purchasing from the Seller; (4) the MWh sales volume; (5) the contract or service schedule that the Seller and Buyer are transacting under; (6) the hourly price of the sale; (7) the hourly revenue from the sale; (8) the point of

excludes any transactions made pursuant to orders issued by the Secretary of Energy under § 202(c) of the Federal Power Act or any transactions with the California ISO or the California PX. The template requires only sellers to submit data, consistent with the information submitted in quarterly reports filed at FERC by the WSPP.[211] However, where a buyer's seller did not submit data, a buyer was allowed to do so.[212] All transactions which originated, were delivered or must be transmitted in the PNW were to be reported.

Beginning on August 16, 2001, the parties began to submit data. However, as detailed in the testimony of Staff witness Poffenberger, the data submitted is incomplete. In terms of the volumes of spot market bilateral transactions, it is not apparent that all entities who may have sold into the PNW market during the relevant time period submitted data. While there are approximately 220 members of the WSPP, only 56 entities responded to the order by either providing data (more than 40 entities) or indicating they had no eligible transactions. Ex. S-4. Thus, there is no indication from approximately 75 percent of WSPP members of whether they participated in the PNW spot market during the relevant time period.

In order to determine which WSPP members did not submit transaction data and obtain a more accurate number of total volumes and transactions, it

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delivery and (9) the California Independent System Operator's Market Clearing Price (MCP) for that hour, as determined in Docket Nos. EL00-95-045, *et al.* Ex. S-3 at 5.

[211] Staff's recommended format at page 1, filed August 3, 2001.

[212] August 9, 2001 Order at 9.

would be necessary to reconcile the names of those sellers listed in the FERC Form No. 1 for each investor-owned utility located in the PNW with the list of those entities submitting transaction data in this proceeding. Ex. S-3 at 8-9. To cite one example, Idaho Power Company's (Idaho Power) 2000 FERC Form No. 1, pages 326.5 through 326.17, indicates that Idaho Power purchased power from numerous sellers pursuant to the WSPP Agreement. *See* Ex. S-7. Sellers listed in Idaho Power's FERC Form No.1 could be compared to the list of entities that submitted transaction data in Ex. S-4 to determine which sellers did not submit spot market sales data in this proceeding. For example, Idaho Power's FERC Form No.1 purchased power data indicate that Idaho Power purchased energy from Reliant Energy Services (Reliant) pursuant to the WSPP Agreement during 2000, but Reliant did not submit transaction data in this proceeding. Such additional information would have to be obtained to determine whether the energy sale from Reliant to Idaho Power was a spot market sale in the PNW and whether it occurred between December 25, 2000 and June 20, 2001. This process would have to be repeated for all investor-owned utilities in the PNW. The time constraints of the instant proceeding, however, did not allow for such further discovery. Thus, the volumes and transactions described in the data submissions made August 16, 2001 and later probably understate the actual numbers involved.

In addition to an incomplete list of sellers and transactions, there are a number of problems with the data that was submitted. Certain sellers were unable to identify a specific upstream vendor because the sales were made from a portfolio of resources

which may include both generation and purchase contracts. Ex. S-3 at 6. Should the Commission determine that refunds are owed in this proceeding, it will likely be necessary to undo those portfolios to determine the upstream vendor(s).

More significantly, since the seller, not the buyer, submitted the information, it is not possible to tell whether the power was used to serve the buyer's load in the PNW or was resold again, perhaps into California. Ex. S-3 at 6. The template shows delivery points not only within the PNW region but also at border points such as COB and NOB. Further, it cannot be determined from the data submissions which transactions included power that originated or was transmitted through the PNW. Ex. S-3 at 7.

The template requested information about the contract schedule and terms and conditions. Most of the responses to the data template indicate that the majority of the sales transactions were made pursuant to the WSPP agreement. Ex. S-6. The remainder were made pursuant to the Seller's market-based rate electric tariffs on file with the Commission or specific bilateral contracts with the buyer. Ex. S-3 at 7.

The WSPP Agreement is a standardized power sales contract that applies to transactions between its 220 members. WSPP members are allowed to sell at market prices if they have received market-based rate authority from the Commission or if they are not regulated by FERC. The three basic products that are available under the WSPP Agreement are set forth in service schedules. Service Schedule A is Economy Energy Service, which is energy that may be interrupted upon notification to the buyer. Service Schedule B is Unit Commitment Service, which is a sale from a specified generating unit for a specified

period of time. Service Schedule C is Firm Capacity/ Energy Sale or Exchange Service, which provides for firm capacity transactions with or without associated energy, firm energy transactions, and exchanges of firm capacity and/or energy. The WSPP Agreement provides that Parties are free to negotiate the specific terms and conditions of a transaction under the service schedules. Ex. S-3 at 8.

A very preliminary review of the data submissions indicates a range of prices for some parties. For transactions greater than one month, one claimant paid prices ranging from $165 to $390 for energy. During the month of January 2001, another claimant paid between $115 and $581 for energy during the peak period. As discussed in Section 2-f, there is some evidence that one party charged a consistent rate at the higher end of this range over a period of three months (January-March 2001).

Staff avers that whether an entity turns out to have been a net buyer or a net seller of electric energy will depend upon the definition of "spot market" in the PNW.

The data template approved by the Presiding Judge provides for transactions to be grouped in four categories:

- transactions of 24 hours or less
- transactions greater than 24 hours and up to one week
- transactions greater than one week and up to one month
- transactions greater than one month and up to one year
- With respect to whether a respondent is a net buyer or net seller, each category will likely produce a different outcome.

2d. What Is The Appropriate Methodology For Determining A Just And Reasonable Rate For Transactions That Occurred In The Bilateral Spot Market In The Pacific Northwest During The Relevant Period?

NPG:

The Commission did not direct the Presiding Judge to determine the appropriate methodology for determining the just and reasonable or "benchmark" price for Pacific Northwest spot market sales during the refund period. Obviously, however, it is necessary to utilize a benchmark price in order to determine the "extent of potential refunds." While the NPG members used different methodologies for determining the benchmark price, they are based on the marginal costs of Pacific Northwest resources. Many issues relating to the appropriate methodology for determining the just and reasonable price are now before the Commission, and the Commission has indicated that it will be addressing these issues in a further order to be issued by October 15, 2001.[213] For the purpose of this preliminary evidentiary hearing, it is clear from the evidence in the record that, whatever methodology is used to determine the benchmark price, [NPG argues] the "extent of the potential refunds" is substantial.

Seattle City Light believes that the just and reasonable or "benchmark" price for use in determining the extent of the potential refunds in this proceeding should be the marginal cost of the highest cost resource that would have been dispatched to serve load in the Pacific Northwest absent the distortion in the

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[213] *See* "Order Granting Rehearing for Further Consideration," issued August 30, 2001, in *San Diego Gas & Electric Co.*

market clearing prices in the California PX and ISO spot markets.

Mr. McCullough determined the monthly benchmark prices by first determining the actual loads during the refund period for the U.S. Northwest Power Pool ("NWPP").[214] He identified the portion of those loads that in fact were met by hydroelectric generation under the then existing drought conditions, generation from the WPPSS 2 nuclear station, and "other generation" that generally is not subject to economic dispatch.[215] Mr. McCullough then determined the thermal resources in the Pacific Northwest that would have been available to meet the remaining NWPP load. The WSCC 2000 Summer Assessment provides a detailed breakdown of the resources that were available in the U.S. portion of the NWPP to meet those loads. Mr. McCullough adjusted those available resources for planned outages and the actual Hunter outage.[216]

Mr. McCullough performed a dispatch analysis pursuant to which he first dispatched the coal resources in the Pacific Northwest region to meet the remaining load, and then the combined cycle units, and finally the high cost natural gas units.[217] The dispatch analysis indicated that the region's coal resources would have been dispatched to serve load in the Pacific Northwest during the months prior to November 2000 and after March 2001. Low cost natural gas units would have been operated from November 2000 through March 2001, and high cost

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[214] Exh. NPG-1 at 13, lines 1-5.

[215] *Id.* at lines 4-5.

[216] *Id.* at 14, lines 3-5.

[217] *Id.* at 14, lines 7-10.

natural gas units would have been operated in December 2000 and February 2001.[218]

Using information in FERC Form 423, which provides the monthly fuel costs for most of the units in the NWPP, it is possible to calculate operating costs on a resource-by-resource basis.[219] However, in light of the severe time constraints imposed by the Commission on this preliminary evidentiary hearing, Mr. McCullough based his benchmark price on the marginal cost of the highest cost unit in each category, *i.e.*, coal, and low and high cost natural gas units.[220] Accordingly, the results of Mr. McCullough's analysis were conservative for two reasons. First, he used the marginal cost of the highest cost unit in each category even though that unit actually may not have been dispatched.[221] Second, absent the price distortions in the California spot markets and taking into account the reduction in the California loads, there were thousands of megawatts of low cost generation in California that would have been available to supply power to the Pacific Northwest during this period.[222] Mr. McCullough added 3.00 mills to cover variable operations and maintenance costs.[223]

Mr. McCullough's analysis of the appropriate benchmark price does not, as it should not, take into account the dysfunction, including the distortions in the prices, in the California PX and ISO spot

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[218] *Id.* at 15, lines 1-3.

[219] *Id.* at 15, lines 6-7.

[220] *Id.* at 15, lines 7-16.

[221] *Id.* at 15.

[222] McCullough Rebuttal Testimony, Exh. NPG-68, at 3.

[223] Exh. NPG-1 at 15, lines 16-17.

markets. Rather, as he notes, it is consistent with the operation of the competitive Pacific Northwest spot market over the past 20 years:

> We have two decades of experience with bulk power markets in the Pacific Northwest. These results reflect the vast majority of market behavior we have observed since 1980. They also reflect good economic logic. Plants are block dispatched in merit order. Prices reflect the incentive required to bring up a unit. There are no arbitrary "market mechanisms" where state officials attempt to direct the market or market participants exert market power.[224]

Contrary to claims by various TFG witnesses, a benchmark for the refund period based on a marginal Pacific Northwest unit is fully consistent with the unified, integrated operation of the California and Pacific Northwest sub-markets. As Mr. McCullough explains:

> Distortions in the California market clearly set the prices for the entire WSCC market, including the prices in the Pacific Northwest. However, absent those distortions, the market prices during the period December 25, 2000 through June 20, 2001, would have been set by the marginal cost of the last unit dispatched in the Pacific Northwest.[225]

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[224] McCullough, Exh. NPG-1 at 17-18.

[225] We would expect the surplus resources in California to compete with Pacific Northwest generation and to provide lower cost alternatives during the winter months. . . . The distortions in the California market were so great and so pervasive that they have tended to obscure the fact that the peak loads in California during the [refund] period . . . were much lower than in previous years, while the amount of capacity was greater than in previous years.).

In order to calculate market clearing prices for the California PX and ISO spot markets in the San Diego proceeding, the Commission recommended that hourly market clearing prices ("MCPs") be calculated by the California ISO ("CAISO") based on the actual incremental heat rate of the regional marginal generating unit, average daily spot gas prices, a creditworthiness adder and an operation and maintenance (O&M) adder. The methodology utilized by Mr. Movish for calculating market clearing prices in the Pacific Northwest is similar to that used in California by the Commission with several regional changes to produce a clearing price that is more appropriate for the Pacific Northwest.

Mr. Movish utilized a hypothetical marginal unit based upon recent historical data for the Pacific Northwest region.[226] Specifically, data for members of the Northwest Power Pool that filed FERC Form 1 for the year 2000 was utilized. The generating plants with the most inefficient operational heat rates firing natural gas were Avista Corporation's Spokane N.E. plant and Puget's Fredrickson plant. The Spokane N.E. plant reported an average net plant heat rate of 13,004 Btu/kWh, while the Fredrickson plant reported an average net plant heat rate of 12,736 Btu/kWh. Averaging the two heat rates yields a hypothetical marginal unit heat rate of 12,870 Btu/kWh.[227] It is important to note that this application of the heat rate of the least efficient units over all hours during the period presents a worst case scenario for periods when demand was low and a more efficient unit was the marginal unit. This

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[226] Movish, Exh. NPG-33 at 20, lines 5-12.

[227] *Id.* at 20, line 4, line 16 to p. 21, line 4.

approach overstates the market clearing price that would have been seen in a functionally competitive market.[228] However, considering that no method is perfect for determining the marginal unit for the Pacific Northwest for each hour, the methodology proposed by Mr. Movish provides a reasonable proxy for such a unit, generally follows the approach taken in resolving overcharges in California, and constitutes an expedient method of resolving refund claims in this proceeding.

Clearly, there are marked differences in gas prices delivered to individual hubs and western subregions. Similarly, as the Commission identified in its July 25, 2001 Order, depending on the location of the marginal unit, whether in the North of Path 15 ("NP15") zone, or the South of Path 15 ("SP15") zone, different gas prices will be used in calculating the market clearing price.[229] Accordingly, to appropriately determine market clearing prices prevalent in the Pacific Northwest region, a gas price specifically for that region must be considered. For the Pacific Northwest region, Mr. Movish used the simple average of daily spot prices reported for the Northwest Pipeline hub at Sumas and Northwest Stanfield compressor station hub.[230] These two hubs constitute major flowgates for gas into the Pacific Northwest, and therefore constitute a reasonable source of supply and pricing for gas-fired Pacific Northwest peaking generation.

To calculate the fuel component ($/MWh) of the market clearing price for the Pacific Northwest, Mr.

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[228] *Id.* at 20, lines 8-12.

[229] *Id.* at 21, lines 10-19.

[230] *Id.* at 22, lines 1-5.

Movish applied the hypothetical marginal unit heat rate of 12,870 Btu/kWh in conjunction with the simple daily average of gas spot prices at the Northwest Pipeline at Sumas and Northwest Stanfield compressor station. To arrive at a calculated market clearing price for the Pacific Northwest spot market, the fuel component was combined by Mr. Movish with the $6/MWh O&M adder as identified by the Commission. McCullough Rebuttal Testimony, NPG-68 at 2. *See also id.* at 3 ("[i]n an undistorted world, no credit worthiness adder was included in the calculation.[231]

The methodology employed by Mr. Movish in calculating a market clearing price does not attempt to incorporate the influences of an unreasonably priced, dysfunctional, California market in its determination of an appropriate market clearing price. Rather, the objective of Mr. Movish's methodology is to determine what prices would have been just and reasonable in the Pacific Northwest spot markets during the period in question based upon a Pacific Northwest located marginal unit which historically has exhibited peaking operational characteristics.

In summary, the methodology employed by Mr. Movish for determining the MCP utilizes the same basic methodology proposed by the Commission in the California proceeding, appropriately uses regional heat rate data and regional historic gas prices, and provides both an unbiased and expedient method that can be applied to quickly correct the harm caused by unjust and unreasonable charges for power in the Pacific Northwest during the period in question.

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[231] *Id.* at 23, lines 9-17.

California Parties:

According to the California Parties, the Commission determined in the July 25 Order that the appropriate methodology for determining refunds in Western Systems Coordinating Council ("WSCC") markets is to develop a just and reasonable mitigated market clearing price on an hourly basis for the relevant time period, and require refunds to be made of prices charged in excess of that mitigated price.[232] The California Parties have utilized the methodology articulated in the July 25 Order, and the unadjusted ISO mitigated market clearing prices which result from it, to develop the value of the refund claim asserted in the testimony in this proceeding.

The California Parties presented their case consistent with the position taken by Commission Staff in developing the template for data submissions in this proceeding, and adopted by Your Honor, in the "Order On Format For Data Submissions," issued August 9, 2001: the refund methodology here should follow the refund methodology ultimately adopted by the Commission in the *San Diego* proceeding. For the same reasons that price mitigation going forward must be equivalent for all regions in the WSCC,[233] the refund methodology must also be consistent across the WSCC.

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[232] 96 FERC at pp. 61,516-519.

[233] In the June 19 Order, the Commission held that "[b]ecause these markets are integrated, the mitigation proposal must establish the same prices for all markets." 95 FERC at p. 62,556. *See also* Wolak CAL-5 at 12:10-13 ("it may be appropriate, due to the nexus between the California and the Pacific Northwest wholesale markets that substantially the same methodology be used in this proceeding that is ultimately used in the California proceeding in EL00-95").

Because both the refund methodology adopted in the July 25 Order and its implementation remain subject to litigation in the *San Diego* docket,[234] the value of the California Parties' refund claims in this case could change depending on the methodology ultimately adopted.[235] Therefore, the refund claim asserted herein should thus be viewed as the *minimum* value of the California Parties' claim.

Certain variations in the implementation of the July 25 refund methodology should be adapted to the PNW. For instance, it may be appropriate to recalculate the MMCP using PNW gas prices. Measuring CERS actual purchases against such a recalculation would provide yet another measure of the refund

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[234] On rehearing, the California Parties have sought modifications to the following aspects of the July 25 refund methodology: (1) utilization of spot gas prices (rather than the monthly gas prices used in the June 19 order for forward-looking price mitigation); (2) imposition of a 10% "creditworthiness adder" on ISO transactions; (3) tripling of the Commission's prior allowance for O&M costs; (4) inappropriately basing mitigated Ancillary Services prices on energy prices; and (5) failing to eradicate the impacts of withholding by declining to impose the must-offer provision on the refund period.

[235] The California Parties have taken the position in the *San Diego* docket that the appropriate methodology for determining just and reasonable rates during the relevant period is to require sellers to make cost of service filings for their entire western portfolios, and to order refunds based on the difference between the unjust and unreasonable prices charged during the relevant period and sellers' actual portfolio cost-of-service. In the alternative, the Commission should determine a just and reasonable rate, and order refunds of charges which exceed that rate, based on the mitigated price methodology applied to the *San Diego* proceeding, with modifications as discussed in the California Parties' Rehearing Request. This position is consistent with the testimony of Dr. Wolak in this proceeding. (CAL-5 at 14:14-15:15).

claim. However, in the limited time available to submit this filing, the California Parties were unable to obtain the necessary data to make such a calculation.

A just and reasonable rate in the PNW should not include a credit premium such as the 10% creditworthiness adder imposed in the *San Diego* docket. Mr. Movish testified that a credit premium would be inappropriate in developing a just and reasonable rate in the PNW for several reasons: (1) there are no unpaid purchase or sales transactions in the PNW; (2) municipal entities do not constitute any real risk of non-payment; and (3) claimants in this proceeding have paid all of their bills, and paid them in a timely fashion. (NPG-33 at 22:7-20). Mr. Movish concludes that a creditworthiness adder should be imposed only where a market participant has either a demonstrated history of non-payment risk, or has not established experience in meeting transaction payment requirements. (*Id.* at 22:20-22). Mr. McCullough testified that the creditworthiness adder was appropriately addressed only to utilities which faced bankruptcy. (NPG-1 at 18:10-19:11). This testimony was unrebutted by any TFG witness.[236]

The creditworthiness adder is inapplicable to CERS' purchases for the same reasons. CERS, a state agency, does not face bankruptcy. Moreover, CERS had access to funding in increments of $500 million, and always kept $400-$500 million on hand, thus ensuring that there was no risk to suppliers of non-payment. (Tr. 854:4-16). CERS has paid all of its

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[236] Although the TFG witnesses espouse certain structural differences between the California and PNW markets, they do not propose an alternative methodology for calculating just and reasonable rates in the PNW.

bills for PNW purchases in a timely fashion—sometimes on the same day as a power delivery to avoid being "cut off" by Powerex. (Tr. 868:8-15; Tr. 978:13-17). As CERS has no demonstrated history of nonpayment risk nor insufficient experience making timely payments, it would be inappropriate to impose a credit premium on top of a calculated just and reasonable rate in the PNW.[237]

Where, as here, unrestrained "market-based" pricing caused a catastrophic breakdown, the Commission is required by § 206 of the FPA to set a just and reasonable rate. Consistent methodologies should be used in the *San Diego* docket and in this proceeding to develop just and reasonable rates for the relevant period. The methodology used must fall within a zone of reasonableness related to cost-of-service pricing.[238] The record in this docket is sufficient to im-

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[237] Staff has taken a consistent position. The August 9 "Order On Format For Data Submissions" required that parties submitting the data template in this proceeding report in Column 9 the "CAISO Market Clearing Price . . . filed in Docket No. EL00-95-000 on August 9, 2001." The ISO's August 9 submission reported both an "unadjusted" mitigated market clearing price, and an "adjusted" mitigated market clearing price. The difference between the two was that the "adjusted" price included the 10% creditworthiness adder. In an e-mail message to the parties sent on August 15, staff counsel stated: "We were asked today to clarify whether Col. 9 [on the data template]—'CAISO's Market Clearing Price' referred to an adjusted or unadjusted market clearing price. For the Pacific Northwest, you should use the unadjusted price." Consequently, the California Parties' claims articulated in the testimony herein reflect no credit premium.

[238] *See Farmers Union Central Exchange Inc. v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984) (while the "delineation of the 'zone of reasonableness' in a particular case may, of course, involve a complex inquiry into a myriad of factors . . . the most

mediately award the California Parties refunds in the amount of $1,512,213,967, as discussed further below.[239] Any such award now, however, must provide that the refund amount would increase should the Commission modify the methodology announced in the July 25 Order as the California Parties have requested on rehearing.

TRG:

TFG avers that the prices reflecting competitive market forces and based on active negotiations between buyers and sellers are just and reasonable. *See* Section IV.B.6 below.

Staff:

Staff asserts that in its June 19 and July 25, 2001 orders, the Commission specified a methodology for calculating refunds for California. If a similar methodology is used here, Staff submits that certain modifications should be considered.

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useful and reliable starting point for rate regulation is an inquiry into costs").

[239] This figure includes the California Parties' claim for refunds associated with exchanges in which CERS participated during the refund period, as described in Issue 2(a). (*See supra* at 16-17). As explained by California Parties' Witness Green, the most generous charge or premium that could be justified for a like-time period exchange would be 20%. (CAL-1 at 8:5-12). To the extent that counter-parties exacted a premium greater than 20% in exchanges in which CERS was a party during the refund period (and some counter-parties exacted as much as a 250% premium), Mr. Green calculated a refund on the basis of the difference between the 20% premium and the higher premium actually charged, multiplied by the unadjusted mitigated market clearing price. The results of this refund methodology are reflected on CAL-12. The California Parties claim a refund of 361,165 MW/h associated with exchanges, or $46,612,324.

One component of the methodology is the use of the daily spot market price for natural gas. In California the gas price used to calculate the market clearing price is tied to whether the marginal unit is located in the North of Path 15 zone or the South of Path 15 zone. Thus, the California methodology recognizes the location of the marginal unit and the probable source of the gas used to run it.

Use of these gas prices as applied to determine a market-clearing price in California may not be appropriate for transactions in the PNW. The natural gas used to generate power in that region also comes from Canada. Use of Canadian gas prices or spot prices at different trading points may more adequately reflect costs.

Mr. Movish for the Net Purchasers Group testified that to determine appropriately the market clearing prices prevalent in the PNW region, a gas price specifically for that region must be considered. Ex. NPG-33 at 20-21. He agreed that as in California, it would be appropriate to use the simple average of the spot price as reported by *Gas Daily*, NGI's *Daily Gas Price Index*, and Inside FERC's *Gas Market Report*. He recommended using the prices at the Northwest Pipeline at Sumas and Northwest Stanfield compressor station. *Id.* at 21.[240]

The methodology for California also calls for a ten percent creditworthiness adder. The Commission found such an adder was appropriate and necessary. The Commission noted that in the California proceedings payment of overdue amounts had not been assured. However, in the instant proceeding, there

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[240] *See also* Ex. NPG-4 at 26.

are no allegations that sellers in the PNW have not been paid by PNW buyers.[241]

Issue 2e: Did sellers of electric energy in spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 charge unjust and unreasonable prices?

California Parties:

According to the California Parties, the Commission, in a series of orders to date concerning the wholesale power market dislocations and wholesale power pricing abnormalities both in California and the Western regions of the United States, has determined that unjust and unreasonable rates were charged by sellers in the California market. The Commission has also recognized, in extending price mitigation to the entire WSCC area, that there is a critical interdependence among prices in the ISO's organized spot market, the prices in the bilateral spot market in California and the rest of the West, and the prices in forward markets. This interdependence is most evident in the interactions between the California market and the PNW market.

California Parties maintain that due to the dysfunctional nature of the California market, which demonstrated the importance of the inelasticity of demand in both markets, the California market poisoned the PNW market, creating in the PNW market the same type of unjust and unreasonable prices that were being experienced in the California market.

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[241] Mr. Movish also testified that to the best of his knowledge, there are no unpaid purchase or sales transactions in the PNW. Ex. NPG-33 at 22. *See also* Ex. NPG-4 at 26; Ex. NPG-1 at 19-20.

Prices in the PNW during the refund period clearly were unjust and unreasonable. The record is replete with empirical evidence demonstrating the lack of any predictable difference in prices between the two regions. CAL-7, taken from the February 1, 2001 report of the Department of Market Analysis of the California ISO, depicts average prices during December 2000 and January 2001 in and outside of California. It provides evidence that sellers of electricity will arbitrage any significant price difference between the PNW and California. As California Parties' Witness Dr. Pechman noted, spot prices in the PNW during the refund period hit an average price for peak hours of $610/MWh and for many months averaged $300/MWh. (CAL-14 at 5:16-17; *see also*, Stegeman, NPG-16 at 16:366-372). Witness Hart, also testifying on behalf of the California Parties, noted that prices charged CERS by Powerex for spot market sales adjusted periodically and unilaterally by Powerex, averaged $462 MW/h. (CAL-9 at 5:6-7). Similarly, Witness Movish for Tacoma and the Port of Seattle testified that, due to dysfunctions in the California market, much higher prices were experienced than actual market conditions would dictate. PNW electric utilities purchasing energy in California were paying higher prices for California sub-market source power. This resulted in a spillover effect into the PNW market. PNW power suppliers, therefore, were able to price at the California ISO and PX price, which was higher than in a functionally competitive market. This, in turn, led to a continuing escalation of both futures and spot market prices throughout the PNW, as well as for bilaterally agreed prices for forward contracts. (NPG-33 at 13:20-25, 14:1-5).

Dr. Pechman testified that "the failure of the spot market in California contaminated the PNW power market by providing the opportunity for generators in the PNW to sell into the California market at very high prices which reflected market power present in California." (CAL-14 at 10:3-6). Similarly, Mr. McCullough testified that "any increase in hourly sales [in the PNW] has simply reflected the unsettled conditions at the California ISO." (NPG-1 at 8:9-10). Mr. McCullough further testified that "[d]istortions in the California market clearly set the prices for the entire WSCC market, including the prices in the Pacific Northwest." (NPG-68 at 2).

Thus, the California Parties argue that a major consideration of the Commission in electing to extend price mitigation to the entire WSCC area was its conclusion in the June 19 Order that "[t]here is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot market in California and the rest of the West, and the prices in forward markets." (CAL-14 at 3:19-4:7). This interdependence was graphically demonstrated between the California and PNW markets in CAL-14 at 4, which shows the tight relationship of California ISO average real time energy costs and WSCC spot prices in the PNW and Southwest.

To pretend that the dysfunctional market in California did not also create unjust and unreasonable rates in the PNW, as suggested to the Commission by the TFG, simply defies reality. Even Enron Witness Van Vactor corroborated Dr. Wolak's testimony, and testified that the California/PNW exchanges have created a single continuous market in which scarcity is experienced simultaneously by all parties, bidding up prices for all. (ENR-1 at 7:24-8:1-3). TFG Witness

Dr. Jones conceded that runaway prices in California influenced prices in the PNW. (PPL-1 at 11:6-12:2, and footnotes 6 and 7 ("it would have been irrational for sellers to ignore the opportunity cost of selling to California when evaluating sales to the Northwest.")).

Further, Seattle's Dr. Mason testified on rebuttal that structural differences between PNW and California markets do *not* imply that the markets are economically distinct. Rather, Dr. Mason testified that whether markets are "close" depends on "the effect price changes in one market have on the other." (NPG-62 at 6:25-7:6). Dr. Mason observed that there was "abundant evidence that price changes in California lead to changes in PNW." (*Id.*)[242]

As Seattle City Light witness McCullough cogently noted, the scarcity value discussed by numerous TFG witnesses simply reflects the distortion that should be corrected by establishing just and reasonable prices. Starting in May 2000, the market apparatus in California created an artificial market for energy in the WSCC. Since May 2000, the price paid in California, and the opportunity cost for all transactions in the WSCC, were the distorted prices in the California market. (NPG-68 at 6-7).

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[242] Similarly, FERC Staff took the position, adopted by Your Honor, that all seller data submissions in this case must include an hourly comparison of the prices charged to the unadjusted mitigated California ISO market clearing price developed in the *San Diego* proceeding. Staff based its position on the Commission's June 19 Order, applying the same mitigated price for all markets in the WSCC. *See* "Order on Format for Data Submissions," issued August 9, 2001 at 6, 9 (adopting Staff's position and requiring submission of the ISO mitigated price with the template submissions).

In summary, California Parties argue, prices paid in the PNW market during the period in question were unjust and unreasonable. The prices were not the product of a workably competitive market, since they have no relation to cost of service based prices or the highest cost operating unit. The prices reflect the operation of the dysfunctional California market. The Commission has determined that unjust and unreasonable prices were charged in the California market due in part to the fact that no viable explanation for such prices has been demonstrated. The same applies here. The Commission should find that unjust and unreasonable rates have been charged in the PNW and should order refunds to remedy this situation.

Several witnesses for the TFG have argued that all prices charged in the PNW bilateral market were just and reasonable. The gravamen of these arguments is essentially that the market during the time frame in question was "workably competitive," and that the premiums over cost of service or marginal cost were justified as scarcity rents or opportunity costs. Their postulations are not supported by the facts.

Initially, according to the California Parties, the TFG testimony ignores the Commission's orders on the California market, and the unjust and unreasonable prices created by the dysfunctional market in California. Nor is there any mention of the Commission's determinations relative to the critical interdependence between prices in the California market and prices in the PNW. The predicate for the testimony of the TFG witnesses is that the PNW bilateral

market is only properly viewed on a stand-alone basis. On its face, this predicate fails.[243]

Witness Jones, for example, opined that the tremendous increase in prices experienced during the refund period merely represented opportunity costs or scarcity rents in an environment of drought, increase in natural gas costs, generating unit outages and tight supplies. (PPL-1 at 5:1-12). Witness Jones further claimed that this type of sustained price spike is economically necessary and desirable if generation investment is to be properly encouraged. (PPL-1 at 13:5-12). These claims are meritless. As the Commission recognized and the evidence shows, the market was not workably competitive.

Efficiency in competitive prices is attained when there is a competitive equilibrium price, where the value of the unit to the marginal buyer (marginal benefit) is equal to the cost of producing that unit (marginal cost). (NPG-62 at 2:24-27, 3:1-4). During the time period in question, the PNW market was not routine. As Witness McCullough testified, the market prices would have been set by the marginal cost of the last unit dispatched had the market been workably competitive, absent the distortions in the California market. (NPG-68 at 2). Indeed, before May 2000, the dispatch of plants in the PNW reflected a very clear relationship between the marginal cost of the highest cost operating unit and market prices. (NPG-68 at 4).

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[243] Essentially, the TFG position is a collateral attack on the Commission's determinations to date concerning the California market. To hold that the prices charged in the bilateral PNW market are just and reasonable necessarily implies that the California market prices were also just and reasonable.

The Commission determined that marginal cost pricing best approximates competitive prices.[244] In its application of its market price mitigation to both the California and Western markets, the Commission concluded that the effective competitive market clearing price is the proxy marginal cost price of the last unit dispatched because this approach is consistent with bidding that would occur in a competitive market clearing auction in which each supplier has the incentive to bid competitively at its marginal costs.[245]

The sellers argued that all variable costs and fixed costs should be in the calculation of marginal costs,

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[244] The Commission noted that, in a competitive market with demand response, high prices during times of reserve deficiency would be legitimate scarcity rents. However, given the lack of demand responsiveness in the California market, when the market realizes that reliability targets are missed, suppliers have a greater incentive to supply at prices above what they would ordinarily bid in a competitive market. Because of the lack of demand response, these prices may not reflect what the market would have established as appropriate scarcity rents and, therefore, may not be just and reasonable. 95 FERC ¶ 61,115, at p. 61,361. The same holds true for the PNW market, certainly for the California Parties. As Witness Pechman testified, it was well known that demand was inelastic in the California market.

As Dr. Pechman noted:

> The demand curve was we do anything to keep the lights on. There was great social disruption as a consequence of the early rolling blackouts and the DWR was charged with buying power in order to keep the lights on in the state and so, therefore, there was no elasticity. There was no room to adjust to different prices to say no, I can't buy at that price. There were no mechanisms in place in which to reduce demand.

Tr. at 1038. California Parties Witness Hart testified similarly, *supra*.

[245] 95 FERC ¶ 61,115, at p. 61,354.

including opportunity costs, scarcity values and marginal capacity value.[246] The Commission found that this was unnecessary because a competitive market will not simply reimburse firms at their own marginal cost, since those firms with marginal costs below the market clearing price will receive scarcity rents to cover their fixed costs.[247] Using running costs as a proxy for marginal costs still permitted more efficient generators scarcity rents because they will receive the price of the least efficient unit dispatched. *Id.* In its June 19 Order, the Commission confirmed that using the marginal cost of the least efficient unit dispatched best replicates prices in a competitive market,[248] and that opportunity costs are not appropriate because energy that is available in real-time cannot be sold elsewhere.[249]

Contrary to the sellers' assertions, the allowance of unjust and unreasonable price levels is not necessary to promote investment in generation. The ordering of refunds will not eliminate adequate price signals required to stimulate adequate investment. As Dr. Pechman stated, generators will invest in power plants if they can expect a reasonable return on their investment. Experience shows that generators are willing to develop generation facilities at prices considerably lower than those experienced in the PNW during the applicable time period. (CAL-14 at 4:17-5:3). Indeed, generators or investors will base power plant decisions on expectations of future prices, and not the experience in 2000 through June 2001. The

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[246] *Id.* at p. 61,363.

[247] *Id.* at p. 61,363.

[248] 95 FERC ¶ 61,418, at p. 62,560.

[249] *Id.* at p. 62,564.

Commission has accepted the current mitigated price of $92 MW/h as not adversely affecting incentives for new generation. (CAL-14 at 5:9, 13-15, 6:7-8).

Likewise, Dr. Jones' definition of a competitive market is flawed. Dr. Jones has modified the standard criteria of competition to allow the ability to institute an increase in price, as long as the increase is not significant or sustained. (CAL-14 at 8:10-19). However, in concluding that the electricity trade in the PNW is workably competitive, he failed to evaluate whether the price increases were sustained or significant. In fact, the testimony of Powerex witnesses refutes Dr. Jones by suggesting that the forward price was appropriate for determining Powerex's opportunity costs (PWX-5 at 4-5) and by describing high and sustained forward prices. (PWX-6 at 10:5, 6-13, 15; 14:3). Thus, if Powerex believed that the market was truly competitive, it would not have used the forward price curves that Dr. Tabors recommends. In addition, the forward market prices are not just and reasonable because the prices cannot be justified on the basis of production costs or replacement costs. (CAL-14 at 13:15-17).

In essence, the collective wisdom of the TFG "dream team" of experts on this issue (*see, e.g.*, Tr. 999:12-14) is that the markets functioned as expected and prices increased to reflect changed circumstances. This claim erroneously assumes, of course, that the PNW market was competitive, and uninfluenced by the California price distortions. As Dr. Pechman explained, these assumptions have no basis, so the conclusion is simply wrong:

> If the Pacific Northwest power market were competitive as he [Dr. Jones] suggests, much of what he claims would be true. However, because market

power was present almost all of the time in the California market during the relevant period, prevailing prices in the spot market were far above efficient competitive levels. In turn, because generators in the Pacific Northwest could sell into this market, their offered contracts were at prices far above competitive levels. Since buyers in the Pacific Northwest had nowhere else to turn they were forced to purchase electricity at excessive prices and provide windfall profits to generators. Thus, the price signal was not, as Dr. Jones suggests appropriate and likely to lead to socially optional decisions but rather a distinction that would lead to inefficient decisions and wealth transfer. (CAL-14 at 18:11-19).

The California Parties conclude, in the end, TFG's entire case rests upon the unrealistic and undemonstrated assumption that the PNW market operated in a workably competitive vacuum and was not in any way connected to the California market. TFG's arguments that the prices charged were just and reasonable are unfounded and represent little more than a collateral attack on the Commission's Orders.

TFG:

TFG argues that the prices charged reflected scarcity conditions in a competitive market in which demand had increased but supply had not. They are, by definition, just and reasonable.

Staff:

Staff states that the number of sellers has not been precisely identified, and the mitigated market clearing price in California is as yet undetermined, it is not possible to give a definitive answer to this question. Further, sellers have not had an opportunity

to justify their spot prices. Additional proceedings would be required.

2.f. Did Any Seller Exercise Market Power, Or Violate Any Conditions Or Limitations Of Its Market Based Tariffs Or Agreements Entered Into Under The Western Systems Power Pool Agreement?

NPG:

NPG argues that this "issue," which was not among those identified by the Commission, was included at the insistence of the members of the TFG, who evidently hold the erroneous belief that absent some other unlawful activity, their charges for electricity cannot be found unjust and unreasonable, no matter how high above marginal cost they might be. As the Federal Power Act and the previous law of this case demonstrates, this issue is irrelevant. Nowhere in the Federal Power Act are sellers of electricity in interstate commerce given the right to charge or collect unjust and unreasonable prices so long as they have not exercised market power or violated any conditions or limitation of any applicable tariff or contract. Moreover, the Commission has already imposed prospective price mitigation and also refund requirements in the *San Diego* Docket upon finding only that the California market structure presented the opportunity for potential exercises of market power that resulted in prices that were outside the zone of reasonableness.[250]

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[250] In the November 1 Order, 93 FERC at p. 61,350, the Commission stated: "While this record does not support findings of specific exercises of market power, and while we are not able to reach definitive conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market

That is not to say, however, that proof of market power does not exist. It can be found, for example, in TFG Exh. 20,[251] and in the very fact that sellers were able to command exorbitant prices for a sustained and significant period of time. With additional time and access to information, such as that already provided to the Commission *in camera*, the members of the NPG have no doubt that a strong case can be made that market power existed and was exercised during the relevant period.

California Parties:

California Parties argue that suppliers in the PNW exercised market power. Equally important, suppliers in the PNW, regardless of their own market power, extracted windfall profits because of the market power that tainted the California markets during the relevant period. Under either scenario, the existence of market power forced purchasers of power from the PNW to endure unjust and unreasonable rates.

The record establishes that electricity suppliers exercised market power in the PNW markets during the relevant period. Dr. Wolak testified that the exercise of market power is made possible by the limited supply response of other actual and potential competitors to price fluctuations such that one or more firms can unilaterally increase the price of electricity paid by load serving entities. (CAL-5 at 5:21-

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power when supply is tight, and can result in unjust and unreasonable rates under the FPA." And in the Order of December 15, 93 FERC at p. 61,999, ("we disagree that, absent exercise of market power, prices are necessarily just and reasonable. Our analysis must be . . . based on a determination of whether the rate falls within a zone of reasonableness.").

[251] Tr. 982.

6:2.) Witness Hart described this exact situation. CERS purchased from Powerex only when other lower-priced sources of supply were completely exhausted. At that point, CERS was confronted with a "take it or leave it" proposition at exorbitant prices unilaterally set by Powerex. (CAL-9 at 4:10-17 and 6:2-7; Tr. 893:6-16.)[252]

TFG-20[253] demonstrates Powerex's capability to set prices independent of the market. TFG-20 verifies that Powerex not only charged prices based upon unjust and unreasonable forward price curves for determining the price of power it offered to sell to CERS, but also exercised additional market power by charging CERS even higher prices. Importantly, on numerous occasions reflected in TFG-20, Powerex charged California greater than the purported $500 "risk adjusted forward value of summer energy." (Peterson PWX-6 at 10.) The ability to consistently charge

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[252] Moreover, as noted by Dr. Pechman for the California Parties (CAL-14 at 11:20-23-12:1-3), Mr. Ken Peterson, the CEO of Powerex Corp., described Powerex's market power in his testimony. That testimony provides, in pertinent part: "Powerex was able to supply large quantities of power to CDWR in peak and superpeak periods, often times on no more than 10 to 20 minutes advance notice, and with tremendous hourly swings in the level of purchases scheduled by CDWR. This shaping of power deliveries for CDWR could only be achieved by drawing on the hydroelectricity generation facilities of BC Hydro. Many of these deliveries literally enabled California to keep the lights on. . . ." (PWX-6 at 8.) As stated by Mr. Peterson, the choice CDWR had was to buy from Powerex or go black. In other words, Powerex had market power to charge greater than competitive prices.

[253] As noted above in footnote 186, TFG-20 purports to be a graphic depiction of the price for wholesale transactions between Powerex and CERS as set forth in the work papers of Mr. Green introduced into the record by Powerex as TFG-19.

prices over a period of time in excess of the purported forward price curve is, in itself, a further strong indicia of market power. It is also consistent with TFG's own definition of market power—"the ability profitably to maintain prices above competitive levels for a significant period of time." (Adamson ENR-10 at 13:7-9.)

The TFG also improperly seeks to engraft a culpability standard on the FPA. Wrongful behavior is not the standard. There is no requirement in the law for the Commission to determine that any particular seller exercised or intended to exercise market power before the Commission may take remedial measures under § 206. Rather, the prerequisite both to fixing just and reasonable rates to be "thereafter in force," under § 206(a) and to order refunds of charges in excess of such just and reasonable rates under § 206(b) is simply that the rates charged have been unjust and unreasonable.[254] As set forth previously herein, the Commission has repeatedly found that the California wholesale electricity market was insufficiently competitive to ensure that unfettered market based rate authority would produce just and reasonable rates and that California and the rest of the West are interdependent.[255]

The tight correspondence in price fluctuations between the California ISO day-ahead and real time prices and spot prices in the PNW, detailed by

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[254] *See e.g. FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) ("The condition precedent to the Commission's exercise of its power under § 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential'").

[255] November 1 Order, 93 FERC at p. 61,349; December 15 Order, 93 FERC ¶ 61,294, at p. 61,984 (2000); June 19 Order, 95 FERC at p. 62,545; *Id.* at p. 62,547.

numerous witnesses in this proceeding, reinforces the accuracy of the Commission's prior findings. (*See, e.g.*, Pechman, CAL-14 at 3:19-4:9; Movish, NPG-33 at 12-17; McCullough Rebuttal, NPG-68 at 2, 6, 13 and 17; Saleba, GSS-1 at 3:15-4:2, 4:15-6:6 and 7:4-11).

Given the Commission's acknowledgment of the inextricable interdependence of the California and PNW markets, the TFG's argument is, in essence, that they may permissibly "piggy back" on prices set by participants that do have market power and exercised that market power. This argument patently violates § 206. Suppliers in the PNW were charging and benefiting from a market power determined price.

TFG:

TFG asserts no seller exercised market power or violated any condition or limitation in its tariff or WSPP contracts. *See* Section IV.B.7 below.

Bonneville/BPA:

Bonneville argues that no party has alleged in this proceeding that BPA exercised market power or violated any rate schedule or agreement, and BPA stated in its testimony that no such rate schedule or agreement violations occurred. BPA-1 at 21. This is the case, in part, because BPA does not establish market-based tariffs under the Federal Power Act. BPA's power rates are established under the Northwest Power Act, not the Federal Power Act, and the Commission's authority to review BPA's power rates is specifically prescribed in the Northwest Power Act. BPA's surplus firm power is sold under a Northwest Power Act rate schedule governing BPA's firm power products and services. *Id.* This rate schedule has a ten-year term and was reviewed and approved on

final basis by the Commission in 1996. *Id.* BPA's WSPP power sales were all made by mutual agreement. *Id.*

Staff:

The Staff did not submit any testimony on the issue of market power. However, it states that Ex. TFG-20 is a graph which plots one seller's price to one buyer over most of the relevant time period.[256] It tends to show that this seller sold consistently at a set price, which happens to be well in excess of the $150.00 California market clearing price adopted by the Commission in its December 15, 2000 order. The graph, however, shows significantly more variations after late April 2001. Should further proceedings be ordered, similar examinations of sellers' prices may be warranted.

Recommendations

The record establishes, that the PN market is part of the broader Western power market. The purchase and sale of electricity is carried out pursuant to the rules and guidance of the WSPP Agreement. For decades the PNW has enjoyed a robust and liquid wholesale power market, which is characterized by hundreds of traders and multiple trading points. Exhibits ENR-1 at 3; AE-1 at 3; NPG-1 at 7: 14-17.

Over 60% of the PNW's power supply comes from hydroelectric. The prevalence of hydroelectric generation provides an inexpensive source of power, but it also subjects load serving entities to weather conditions (*i.e.*, drought and resulting low-flow conditions). Faced with seasonal and year-to-year variations in

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[256] See discussions at Tr. 908-914 (*in camera* session) and Tr. 987-995. The later discussion of this document in the transcript was not held *in camera*.

water and storage availability, PNW parties have long been accustomed to buying and selling with each other and with parties outside the region to ensure that supply matches demand.

Following construction of the Northwest-Southwest Intertie in 1970, seasonal exchanges of power with California, Arizona and New Mexico became commonplace. The normal water flow from May to July, coupled with a winter peaking demand profile, has enabled the PNW to export large volumes of "economy" energy during summer months, when its loads are low, but loads to the south are at their highest levels. In return, the PNW historically has relied on surplus thermal generation from California and the Desert Southwest to supplement local supplies during winter cold spells, when loads to the north are high in comparison to loads to the south. Exh. ENR-1 at 9.

The presence of an extensive and comparatively uncongested transmission network (on a historical basis) also has contributed to the development of a fluid wholesale power market in the PNW. BPA owns and operates the majority of the high voltage transmission facilities in the region. Long before the advent of Commission Order No. 888,[257] BPA allowed parties access to its transmission grid. Exh. AE-1 at 3. As a consequence, the Mid-Columbia hub in Eastern Washington is recognized as one of the most flexible trading points in the nation. Exh. ENR-1 at 12.

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[257] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 *Fed. Reg.* 21,540 (May 10, 1996), *FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996* ¶ 31,036 (1996) ("Order No. 888").

Due to a robust bilateral wholesale market, there has never been a centralized power exchange in the PNW. There is no single market clearing price in the region. Exh. ENR-10 at 12. Energy is bought and sold continuously on a bilateral basis, subject to the principles set forth in the WSPP agreement. Each utility is free to choose how to meet its firm load requirements as it sees fit and no one is captive to a single market or a single point of supply. As noted by Eugene Water and Electricity Board ("EWEB") witness Spettel, transactions "are negotiated at arms-length between willing buyers and sellers . . . [and] often times reflect unique and specific circumstances between the parties engaged in each transaction." Exh. NPG-68 at 7. See also TR. at 566-67; Exh. ENR-1 at 13; Exh. PWX-1 at 21; Exh. BPA-1 at 22; Exh. ENR-10 at 11; Exh. IE-2 at 13; Exh. PPL-1 at 21.

As a result of the availability of many traders and trading points, purchasers in the PNW have numerous options in developing a portfolio of power supply. Depending upon their perceived needs and tolerance for risk, load-serving entities can buy power for the next hour, the next day, the balance of the month, monthly, quarterly or for a term of one or more years. Exh. NPG-74 at 6. As observed by Dr. Tabors, risk-averse load-serving entities can assemble a portfolio of long, medium and short-term contracts and, thereby, minimize their exposure to volatile spot market prices. Exh. PWX-1 at 21. In the PNW, shortages in the availability of hydroelectric generation are constantly assessed and general trends are predicted months in advance, consequently PNW purchasers tend to make extensive use of forward contracts (*i.e.*, transactions with durations longer than 24 hours). Indeed, over 99% of the City of Seattle's net purchases

during the December 25,2000-June 20, 2001 period were made under forward contracts; the corresponding figure for Tacoma Power approximates 62.5%. Exh. PWX-3.

Two additional characteristics of the PNW market are directly relevant to the justness and reasonableness of bilateral spot market prices in the region. First, demand in the region is more price sensitive (that is to say, "elastic") than in other parts of the West due, in part, to the presence of a number of energy intensive industries, such as aluminum smelting. Exh. ENR-1 at 11. Those consumers have exercised and, indeed, regularly exercise their ability to respond to price signals by decreasing consumption. Demand responsiveness by PNW consumers was a very important factor in bringing prices down in the PNW in 2001, and an important indicator that the PNW markets were functional throughout the potential refund period. Second, prices, particularly in the forward markets, are extremely sensitive to movements in the cost of natural gas. Exh. ENR-10 at 24-27. Electric prices rose dramatically in the PNW when increased demand for natural gas caused prices to skyrocket in the latter part of 2000, as drought conditions restricted the availability of hydroelectric generation.

There are factual differences between the California ISO/PX markets and the PNW. In California, load-serving entities (comprised almost entirely of California's three large investor-owned utilities) were forced to divest much of their generation, to sell power from what generation remained to the ISO/PX and then buy back all of their requirements through a centralized clearing house at an administratively determined price. Because that price was tied to the

bid of the most-expensive generating unit operating within the market at the time, it did not necessarily reflect the value placed on those transactions by any individual buyer. Exh. PWX-1 at 16. Additionally, having to rely entirely on spot market sales, California buyers were effectively prevented from hedging their risks or balancing their portfolio through forward contracts. In its November 1, 2000 Order,[258] the Commission expressly found this to be a fundamental problem with the California market. Exh. ENR-10 at 11.

Buyers in the PNW faced no such constraints. Load-serving entities, for the most part, retained their own generation, were free to negotiate supply contracts on their own terms and conditions in spot and forward markets, and, as a consequence, paid prices that reflected the value that willing buyers and sellers placed on those transactions in the face of supply constraints. Exh. PWX-1 at 16. For many years PNW buyers have been free to enter into short, medium, and long-term contracts to achieve a hedged and balanced portfolio. "Participants in PNW markets made their own decisions regarding purchasing strategies and contract terms, not only in the period covered by this proceeding but for years leading up to this period." Exh. PWX-1 at 6:14-16; 7:8-10.

The hearing record documents in detail the successive shocks that the western power market experienced leading up to and during the period at issue:

> The disruption and price explosion in the WSCC from May 2000 through June 2001 were the consequence of market fundamentals, exacerbated by financial uncertainty and confusion. There were

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[258] November 1 Order, 93 FERC at p. 61,359.

four compounding events that caused price to rise and to remain at elevated levels for fourteen months. In the first wave, the summer of 2000, high demand growth and hot weather combined to create capacity shortages in California, with resulting price spikes. In the second wave, cold weather smacked the PNW earlier than expected and with much greater severity than normal. The cold weather coincided with the season in which the natural stream-flow in the region's hydro system is at its lowest, and with the planned reconditioning of many of California's thermal generators due to heavy usage in the summer of 2000. The natural gas delivery system was stretched to its limit, inventories reached historic lows, and gas prices peaked at thirty times the level of the year before. In November and December, precipitation remained at record low levels and the power industry became increasingly anxious about the possibility of a serious drought. The Power Planning Council's October warning appeared all the more prescient. In January 2001, the first formal projections on snow pack became available and provided alarming evidence of dry conditions, bringing a third wave of dread to the Western power market. In the meantime, PG&E and Southern California Edison were not able to pass on to their customers the high prices they had had to pay for power in November and December due to frozen rates imposed during market restructuring. Both utilities defaulted on their obligations to their suppliers, including many PNW utilities. The growing financial risk created the fourth and final wave, as essential trade shrunk and the WSCC split apart in autarky.

Exh. ENR-1 at 19:13-20:11.

The evidence further shows that The PNW was faced with an extreme and rare contraction in available supply. To accommodate the shortage, prices rose dramatically, but that is exactly what they are supposed to do. Higher prices provoked a drop in demand and an increase in alternative supplies. Once it was clear that the functions of demand and supply would accommodate the projected shortfall, prices collapsed with extraordinary speed. Exh. ENR-1 at 19:13-21:1; *see also* Exh. NPG-16 at 16:327-17:349; Exh. IE-2 at 2:22-3:4; Exh. IE-4, Appendix F.

The market for electricity in the PNW was affected to varying degrees by these factors, all of which worked together to raise the price of electricity as is normally expected in a workably competitive market when supply is scarce. Ex IE-2 at 25-26.

Furthermore, the evidence also establishes that the PNW utilities were generally forewarned of potential supply shortages. For instance, since 1999 BPA had expressed concerns about a potential energy deficit in the region. Exhs. Enr-1 at 13:22-15:2; NPG-74 at 9:21-10:5; NPG-4 at 14:305-310; NPG-16 at 16:362-366.

As Ms. Green and others acknowledged, in 2000 and 2001, the PNW experienced the worst drought in the last 50 years. See Tr. at 592:19-593:4; *see also* Tr. at 610:20-611:10. Combined with increased demand from population and technology growth ("one dot-com company can use 20-40 megawatts per day, the same as the entire [Seattle-Tacoma] airport."), this drought caused an unprecedented increase in prices. Tr. at 610:20-611:10. The record also establishes that increased demand for electricity contributed to increased input costs (*i.e.*, higher demand for electricity resulted in higher demand for natural gas,

causing the price for gas to increase). *See* Exh. ENR-10 at 28:4-5, 12-15 ("In addition to dramatic changes in market conditions for natural gas in the Northwest, a second major factor that must be considered is the impact of hydrological conditions. . . . Just as the natural gas market was making it more costly to offer forward electricity contracts, the weather was reducing the ability of hydroelectric operators to enter into such forward commitments. Available supply was therefore contracting, which put further upward pressure on prices.").

In addition, in California, increased demand, unavailable generation, and credit concerns with California buyers all exacerbated the situation. Exh. NPG-53 at 5:4-10.

The record evidence demonstrates that the PNW market for spot sales of electrical energy was at all times between December 25, 2000 to June 20, 2001 competitive and functional. Exh. PWX-1 at 20:16-21:3.

Dr. Jones explained that there has been no showing of market power or other evidence indicating members of the TFG did any thing other than reflect their competitive market expectations in their bilateral contracts. Exh. PPL-1 at i.

The evidence shows that the Pacific Northwest performed just as workably competitive markets would under adversity. For instance,

- "As prices increased during 2000-2001, investors/suppliers responded, proposing new capacity additions. On the demand side of the price signal, consumers went to work, reducing energy use and adopting conservation techniques. . . . As a consequence of this competitive response, prices for elec-

tricity in the PNW have fallen dramatically." Exh. PPL-1 at 14:7-13.

• "Notwithstanding the shortages of energy in the Pacific Northwest, the market was sufficiently competitive to enable purchasers to be selective about the energy product that they were purchasing. As a consequence, purchasers were able to dictate certain key terms of transactions to sellers, such as firmness and point of delivery." Exh. PSCO-1 at 11:12-16.

• Port of Seattle reported in May 2001, "[m]any experts are forecasting not only sustained periods of high prices but also shortages of electricity in 2001. Staff believes it is critical that we not only take measures to reduce the cost of electricity through conservation . . . , but find a reliable and stable source of electricity for the Airport's future needs." Exh. TFG-8 at 1, PS 1570.

• Port of Seattle also reported "[f]our different companies have approached us on . . . the option of self-generation. . . . Implementing energy conservation projects and programs [has] reduced [our] consumption by over 10% already and may get to 15% in another month. Long term we believe we can reduce energy consumption by 20-25% from our current base." Exh. TFG-5 at PS 1529.

Mr. Van Vactor also explains how the Western power market crises moderated:

> The Western power crisis has alleviated due to a significant drop in consumption. In the PNW, many industrial customers agreed to shut their plants down and sell the power back to the supplier. In California, the long-postponed retail rate increase finally went into effect in June [2001].

> That combined with a conservation program dropped demand by more than five percent. At the same time new, and more efficient, generating resources came on-line. Summer weather returned more or less to normal and spot prices have returned to normal levels. Ex. ENR-1 at 20:14-21:6.

Dr. Tabors observed, "[T]he bilateral markets in the PNW, . . . which have been in existence for more than two decades, worked through a confluence of adverse circumstances in 2000 and 2001, and have now regained equilibrium. Conservation resulted from price signals, demand was reduced, load was shed, and prices came down. These are not indications of a broken market in the PNW, but of one that works. It should be left alone to function." Exh. PWX-12 at 10:6-11.

The evidence also establishes that claimants witnesses conceded that sellers who engaged in the business of marketing electrical power face no barriers to entry. *See* Tr. at 770:24-772:3. Dr. Mason testified unconditionally that for sellers who are marketers that "[t]here are no barriers to prevent them [from] buy[ing] and resell[ing]." *Id.* Likewise, another of the claimants' witnesses, Dr. Pechman, admitted that he conducted no econometric or price elasticity studies to support his contention, contrary to the evidence, that demand in the PNW does not respond to price.

Seattle witness Mr. McCullough observed:

> One reason why real world commodity exchanges avoid the administered prices of the California model is that these types of markets have proven relatively easy to manipulate. Manipulation of prices in the WSCC outside of California is difficult since no central authority can be "gamed."

Exh. NPG-1 at 7:19-22.

It is interesting to note that refund advocates do not seek any structural changes in the operation of the markets governed by the WSPP Agreement.

In making my recommendation I am cognizant that the Commission has rightly refused to extend refund liability to other California markets in which prices were apparently "influenced" by the ISO and PX prices but where no structural flaws existed. Additionally, the Commission has stated in the past that it should minimize its intervention in otherwise well-functioning market mechanisms.

> We emphasize that, by design and definition, spot markets must be allowed to reflect the price swings which capture their temporal nature. In markets such as these, which are the closest to when demand must be met, sufficient supply often manifests itself by dramatic price drops while tight supply can produce dramatic price increases. This is the nature of spot markets. *Those who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases.*[259]

The record evidence establishes that Tacoma chose to take the risk of high spot market prices. Exh. NPG-57 at 3. If the position of the refund claimants is accepted, they would be relieved of the consequences of their conscious economic decisions at the expense of a functioning competitive market in which a vast majority of the PNW purchasers during this period accept responsibility for the choices they

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[259] December 15 Order, 93 FERC at p. 61,996 (emphasis added).

made. For instance, Seattle recognized in September, 2000 that the Centralia sale left it "more dependent on the market than we have been historically." Exh. PPL-1 at 21 n.19. Tacoma likewise sold its [80 MW] share of the Centralia production. Exh. NPG-57 at 3.

Purchase of forward contracts was another option available throughout the PNW to reduce reliance on the volatile spot market. Tr. at 656:15-657:4. In September 2000, TFG member Powerex offered forward contracts for delivery of power during the first quarter of 2001 at $75.50 and $81 per MW. Tr. at 689:11-690:21; Exh. TCE-2. Tacoma now asks the Commission to give it, through refunds, rates it rejected in the marketplace. The correlation between spot market prices and forward market prices is not one-to-one. In fact, by one measure, only 57 percent of the variance in third quarter 2001 forward prices was explained by variance in the Dow Jones Mid-Columbia Index during the first and second quarters of 2001. Tr. 724:6-25-725:1-13. Utilities separate short-term from forward-market trading and compare the prices quoted for these different products when they make resource decisions. Exh. TFG-1; Tr. 581:7-19; Tr. 598:4-8; Tr. 643:9-23; Tr. 656:15-25-657:4. Long-term transactions (*i.e.*, those involving power delivery that is not either immediate or prescheduled over a very limited number of days) are the most predominant and important class of transactions in the region. Exh. NPG-1 at 8:22; Exh. NPG-1 at 10:2-3.

For a number of years preceding the refund period, wholesale electricity market prices in the PNW were, according to Tacoma's Ms. Stegeman, "quite low." Exh. NPG-16 at 14. *See also* Exh. IE-2 at 28:15-20. By electing to rely on the spot market during this

period, refund claimants benefited financially. Now the refund claimants are rebalancing their portfolios by returning to BPA or by acquiring interests in new generation facilitites. Exh. TFG-8 at 2. Tacoma installed a 48 MW diesel generation project and entered into exchange agreements with other power suppliers. Exhs. NPG-15 at 18; NPG-57 at 5. These responses by refund claimants are proof that the market is functioning properly and that it continues to offer choices to its participants.

Buyers who wanted to hedge in the Pacific Northwest could have done so. There were various tools available. Exh. IE-2 at 14.

Therefore, in light of the above I recommend that the Commission not order refunds in this case because the prices were not unreasonable and unlike the California ISO/PX, the market is a competitive market. Furthermore, the prices in the California ISO/PX were not the only factor driving the prices. There was a drought, which limited supply, the price of natural gas rose and demand increased. Spot market bilateral sales constituted only a small percentage of the total volume of transactions in the region because forward contracts are heavily relied on. Spot market sales took place under diverse prices, terms and conditions. Most market participants were both buyers and sellers. In reaching my recommendations I am cognizant of prior Commission orders establishing market based pricing to foster competitive markets. In the case before me, where all transactions are bilateral transactions under the aegis of the WSPP Agreement this is more compelling. The prices were agreed to between willing buyers and willing sellers.

In making my recommendation and based on NPG's and California Parties' allegations I have re-read the April 26 and June 19 orders and conclude that these orders do not support these parties contentions that the Commission has already determined that the prices in the PNW were unjust and unreasonable. First, if that were the case, why would the Commission institute this preliminary evidentiary hearing. Second, the June 19 order refers to the dysfunctionalities of the California market. Third, and most significant, (a factor not mentioned by these parties) the Commission ordered the western market mitigation plan "based upon the need for uniform pricing throughout the western region." slip op at pg. 47. Finally, the April 26 order started an investigation, it was not a decision on the reasonableness of the rates.

There is no evidence of the exercise of market power in this case. For instance, Seattle witness Mr. McCullough stated in his rebuttal testimony that: "The Pacific Northwest market over this time period was a price taker," which means that no entity in the region was able to exercise market power. Other expert witnesses admitted that they had no evidence of market power in the PNW. Philip Movish, witness for Tacoma, Port of Seattle, and Northern Wasco, admitted that there were a substantial number of sellers in the region, particularly in this time period. Tr. at 727. An allegation of the exercise of market power was made on cross examination of Dr. Tabors. As Dr. Tabors explained, exhibit TFG-20 shows the price line for the fixed price sales by Powerex to CDWR. The exhibit also shows the prices Powerex charged for other sales to CDWR during the refund period, and purchases made for aggregation services. (Tr. at 914-15, 920-22). California bought 45,000

MWH at $500 per MWH price, under a $22.5 million 3 day credit limit set by Powerex. This was equivalent to a $225 million monthly credit limit. Tr. at 868:22-869:7; 870:21-25. Powerex made more than 30,000 sales, purchases and exchange transactions in the market during the relevant period. It was a net spot market purchaser in the PNW during the potential refund period (Exh. PWX-10, p.3). Tr. at 862:5-863:26; Exhs. PWX-1-6 at 15; PWX 5 at 6. I find that the evidence in this case does not show the exercise of market power by any one company.

At Issue 1, above, I made recommendations concerning the claims of the CDWR/CERS. If the Commission orders additional proceedings, the issues set forth above, may need to be considered (whether these transactions were spot market or not, *etc.*).

Although I ordered that non-jurisdictional utilities submit data in this proceeding in order to develop the record, I agree with Bonneville and other non-jurisdictional entities that the rationale previously used by the Commission to assert jurisdiction over non-jurisdictional entities does not seen to apply to this market because of the differences between the Pacific Northwest and the California ISO/PX. If the Commission orders refunds, this issue must be addressed. If refunds are ordered and the non-jurisdictional entities are excluded, this would differentiate sellers subject to refunds in the market. In making this recommendation, I give significant weight to the fact that the majority of the transactions in this market are bilateral transactions under the WSPP Agreement.

Staff's explanation of the data submissions corroborates the Commission's statement that unraveling these transactions is to be mildly stated a com-

plex task. The data submission have been certified to the Commission as part of the record in this proceeding. The data submissions are incomplete. It appears that all entities who may have sold into the PN market during the relevant time period did not submit data, of 226 members of the WSPP, only 56 entities responded to the order by either providing data or indicating they had no eligible transactions. To determine entities who did not, a reconciliation with FERC Form No. 1 would have to be undertaken. In addition, as stated above there are problems with the data submitted. If the Commission decides to order refunds, portfolios of resources would have to be undone to determine upstream vendors. Furthermore, from the submissions it cannot be determined whether the power was used to serve the buyer's loads in the PN or was resold again, perhaps into California, nor the power that originated or was transmitted through the PNW. The data does show that most of the transactions were made pursuant to the WSPP Agreement or market based rate tariffs on file with the Commission, or bilateral contracts. The data shows a range of prices listed above.

Based on my recommendations above I am not making any recommendations on the specific methodology to be used for determining the amount of refunds. However, I set forth above, all the parties' proposals. I find persuasive that because of the distinctions of the market, if the Commission orders refunds, adjustments must be made from the refund protocols established in the California proceeding. Staff's recommendations are persuasive with regard to this matter.

The record shows that although the California prices affected the prices in the Pacific Northwest,

this was not the only thing driving up the prices in the PNW. Therefore, under these circumstances, and based on the specifics of the PNW market and the evidence developed in this case (the market has for years been a competitive market, there is ample competition in the market based on the number of sellers, buyers and trading points, the market shows instances of self correction) I recommend that the Commission not order refunds in this case. I am not persuaded by the arguments made by the California Parties and the NPG. They failed to establish by preponderance of the evidence that the prices in the Pacific Northwest were unjust or unreasonable. Furthermore, I find compelling that the transactions in this market, unlike the California market, are bilateral agreements, and have been so for years, under the WSPP Agreement. It bears mentioning that the majority of participants in this proceeding were against refunds.

3. Are refunds lawful or appropriate for spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 and what is the extent of any potential refunds?

The Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission maintain that it is not equitable to order refunds because of limitations on the Commission's jurisdiction over many buyers and sellers of wholesale power in the Pacific Northwest, and because of the Commission's direction to examine only spot market transactions. Under these circumstances refunds would be discriminatory, and disruptive of orderly regulation. It asserts that there is no objective measure for determining whether the prices

were unjust and unreasonable and to what magnitude. A large portion of the power bought and sold in the Pacific Northwest is sold by non-public entities. If the Commission cannot legally impose refund obligations on these sales, the burden of paying refunds will fall on a limited class of jurisdictional sellers in the region; and the benefit of receiving refunds will be available only to buyers who bought form those same sellers.

NPG:

NPG contends that sellers charged, and consumers paid, unjust and unreasonable prices in the Pacific Northwest spot markets during the refund period, whether refunds are "lawful and appropriate" is a matter for the Commission, rather than the Presiding Judge, to determine. The Commission has not asked the Presiding Judge to advise it on this matter.[260] Nevertheless, such refunds are certainly "lawful" because they are authorized by Section 206(b) of the FPA.[261]

Ordering refunds of the unjust and unreasonable charges borne by the consumers of Seattle, Tacoma, Port of Seattle, Eugene, Northern Wasco and other Pacific Northwest communities is certainly "appropriate" NPG argues. The Commission has ordered refunds for the benefit of California's citizens,[262] and consumers in the Pacific Northwest should also be

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[260] *See* July 25 Order, 96 FERC at p. 61,120.

[261] *See* 16 U.S.C. § 824e(b) (1994) ("the Commission may order the public utility to make refunds of any amounts paid, for the period subsequent to the refund effective date . . . in excess of those which would have been paid under the just and reasonable rate").

[262] *See* July 25, Order, 96 FERC ¶ 61,120.

protected by the Commission from unjust and unreasonable charges. Even Puget, a prominent TFG member, has acknowledged the unfairness that would otherwise result: "it is unfair and unduly discriminatory to protect wholesale purchasers in California . . . and yet deny similar protection in another part of essentially the same market, *i.e.*, the Pacific Northwest."[263]

Congress did not distinguish between or among the forms of contract under which remedies for unjust and unreasonable prices may be imposed. Instead, it directed the Commission's attention to the subject matter of the transaction—the price charged for energy. When unjust and unreasonable prices have been charged, irrespective of contract type, Congress provided the Commission with remedies. The Commission's delegated authority to grant relief from unjust and unreasonable rates arises from Section 206 of the Federal Power Act, which then creates the statutory obligation to fix a new rate or to fix practices to be thereafter observed, if the Commission

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[263] Puget Complaint at 10. Contrary to the impression it has since sought to convey, *see, e.g.*, Tr. 69. Puget's Complaint explicitly recognized that relief that was "prospective" on October 26, 2000 could ultimately involve refunds. The Complaint specifically requested that: [I]f and to the extent any refund is called for in response to PSE's petition, PSE respectfully requests that the refund effective date be set, in accordance with Section 206 of the Federal Power Act (16 U.S.C. § 824e(b), sixty (60) days after the date of the filing of this Complaint. Puget Complaint, at 11. *See also* Puget Complaint at 13. Notably, Puget's Complaint declined to seek an earlier effective date not on the ground that the Commission could not lawfully do so, but because Puget thought an earlier refund date would be "unfair" due to "the operation of the seasonable flow of power between California and the Pacific Northwest." Puget Complaint at 11, n. 7.

finds that a rate no longer meets the just and reasonable standard.[264] Thus a bilateral contract under which unjust and unreasonable prices were extracted is susceptible to remedy by the Commission, and refunds are an appropriate and legal remedy under the Federal Power Act, according to NPG.

Furthermore, NPG asserts, the parties opposed to refunds—the TFG—contend that unjust and unreasonable prices should be left unrectified because determining refunds allegedly would be too complex a matter. Having invented the inapt term "ripple claims," the TFG through its witnesses claim that "[i]f refunds are ordered, other market participants (perhaps most) will be forced to assert 'ripple' claims, unwinding a vast web of transactions across the entire western market."[265] These allegations about "ripple claims" are a red herring. Parties opposed to refunds requested and received permission during a prehearing conference *not* to introduce in this preliminary proceeding information on any "net" amounts or refunds due them from other entities. They made this request so as to avoid being in the awkward litigation posture of opposing refunds while at the same time identifying refunds they claimed were owed them.[266]

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[264] 16 U.S.C. § 824e(a).

[265] Van Vactor, ENR-1 at 3.

[266] *See, e.g.*, Transcript at 104 (Counsel for Constellation: "I don't want to have to stand out there and demand refunds that I don't think are appropriate . . . . But I also don't want to inadvertently waive my rights in the event something goes forward"); Transcript at 140, lines 10-12 (Counsel for Duke Energy: "by making the ripple testimony such a central feature here, in effect you're asking everybody to take that side of the case"); *id.* at 141, lines 6-12 ("But to ask parties simultaneously

According to NPG, all parties are quite capable of revealing *at one time* the bilateral spot market purchases and sales they made, the prices they charged and paid, and to whom and by whom they are owed refunds. The NPG members that have submitted affirmative refund requests did so, in a mere fifteen days.[267] Once the Commission clarifies the bilateral spot market transactions to be subject to refunds, and adopts a market mitigation price, all Pacific Northwest market participants will be able to submit purchase and sales data and their refund claims, if any. Rather than the TFG's metaphorical "ripples" or the "unwinding" of a spider web, refunds can be determined in one simultaneous reconciliation.

Additionally, NPG avers that TFG witnesses make various claims to the effect that granting refunds would constitute "regulatory intervention" in a "well functioning bilateral electricity market" and "would skew incentives and undermine . . . efficiency."[268] They overlook the fact that the Commission has already determined that Pacific Northwest bilateral spot markets were dysfunctional and has established prospective price mitigation for such markets through September 30, 2002.[269] Moreover, TFG witnesses fail to explain how net sellers making, and net purchasers receiving, a one-time refund payment would change

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to be arguing against affirmative claimants . . . and at the same time have to take the exact opposite position just strikes us as putting us between a rock and a hard place."); *see also* the responses of the TFG members to the Second Discovery Requests of the City of Tacoma and Port of Seattle.

[267] *See, e.g.*, Exhs. NPG-70 through -72 (the Direct Cases and Requests for Refunds filed by NPG members).

[268] Van Vactor, Exh. ENR-1 at 3-4.

[269] *See* June 19 Order, 95 FERC at p. 62,549.

the prospective prices and economic incentives facing market participants. It obviously would not.

Finally, NPG asserts, TFG witnesses make the disingenuous claim that the unjust and unreasonable Pacific Northwest prices should not be rectified because parties seeking refunds allegedly have "unclean hands." With no support but their own misconstruing of NPG testimony, TFG witnesses contend that NPG members were able to "cash in" by "purchasing power . . . when prices were low and selling . . . when prices were high."[270] In particular, the TFG contends that the period covered by this proceeding fails to include summer months when, the TFG alleges, NPG members were net sellers.[271] These claims are disingenuous because NPG members *would like* to extend the refund period back to cover the summer of 2000 and have not profited from sales of surplus energy.[272] Indeed, the City of Tacoma and Port of Seattle have already filed a Petition for Review of the July 25 Order on precisely this issue.[273]

In sum, NPG concludes, it is certainly legal and entirely appropriate for the Commission to order

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[270] Jones, PPL-1 at 24.

[271] Tabors, PWX-1 at 45.

[272] *See, e.g.*, Rebuttal Testimony of Paula S. Green, Exh. NPG-67 at 7 ("Seattle supported the longer refund period requested in the California settlement conference"); *id.* ("Seattle was a net purchaser in the spot market for the entire period May 2000 to June 20, 2001"); *id.* ("Seattle has not profited, and does not profit from surplus sales").

[273] *See City of Tacoma, Washington, and Port of Seattle, Washington v. FERC*, Case No. 01-1337 (D.C. Cir., filed July 31, 2001), consolidated with *Turlock Irrigation District v. FERC*, Case No. 01-1289 (D.C. Cir., filed June 27, 2001).

refunds of the unjust and unreasonable charges collected in the Pacific Northwest.[274]

California Parties:

California Parties argue that the Commission has the authority to order refunds in this case and should do so in order to prevent a windfall to PNW sellers and to deter future market abuses. California consumers are entitled to a refund in excess of $1.5 billion. The Commission may lawfully order refunds pursuant to its authority under § 206 of the FPA,[275] for spot market bilateral transactions in the PNW during the refund effective period. The Commission has broad authority to implement remedial measures in response to unjust and unreasonable rates, including the express authority to order refunds:

> At the conclusion of any proceeding under [§ 206], the Commission may order the public utility to make refunds of any amounts paid . . . in excess of those which would have been paid under the just

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[274] Whether the Commission may exercise jurisdiction over non-public utilities is presently under review by two United States Courts of Appeals. *California Public Utility Commission v. FERC*, Case No. 01-71051 (9th Cir., filed June 29, 2001); *Turlock Irrigation District v. FERC* (D.C. Cir., filed June 27, 2001), consolidated with *City of Tacoma, Washington, and Port of Seattle, Washington, v. FERC*, Case No. 01-1337 (D.C.Cir., filed July 31, 2001). Until such time as the Commission's Order of July 25, 2001, is modified or reversed in that regard, it is the law of this case that the Commission has jurisdiction over such utilities for purposes of this proceeding. July 25 Order, *slip op.* at 25-30. *See, e.g., Christiansen v. Colt Indus. Operating Corp.*, 486 U.S. 800, 816 (1988), *citing Arizona v. California*, 460 U.S. 605, 618 (1983). *See also* 18 Moore's Federal Practice, § 134.20[2] (Matthew Bender 3d ed.).

[275] 16 U.S.C. § 824e.

and reasonable rate ... which the Commission orders to be thereafter in force.

According to the California Parties, the establishment of the December 25, 2000 refund effective date is lawful. As the Commission discussed in the July 25 Order, § 206 authorizes the Commission to establish a refund effective date no earlier than 60 days after the date that a complaint is filed or the Commission initiates an investigation.[276] Here, the refund effective date is 60 days after the date on which the Puget complaint was filed. Refunds are a form of equitable relief, and the general rule is that the Commission should order restitution when it would "give offense to equity and good conscience" if a refund were not ordered.[277] The key considerations include whether a party will experience a windfall or unjust enrichment absent a refund, whether a refund will deter future abuses, and whether the equities favor a refund.[278]

During the refund period, California Parties maintain, there was an enormous transfer of wealth from buyers to sellers. The clearest single example of this transfer is the price paid for purchases made by CERS in the PNW on behalf of California ratepayers in order to "keep the lights on." CERS purchased power at an average rate of $390 MW/h; it paid

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[276] 96 FERC at p. 61,505.

[277] *Towns of Concord, Norwood and Wellesley v. Fed. Energy Reg. Comm'n*, 955 F.2d 67, 75-76 (D.C. Circ. 1992) *citing Atlantic Coast Line R.R. v. Florida*, 295 U.S. 301, 309 (1935).

[278] *Koch Gateway Pipeline Co. v. Fed. Energy Reg. Comm'n*, 136 F.3d 810 (D.C. Circ. 1998) (windfall); *Laclede Gas Co. v. Fed. Energy Reg. Comm'n*, 997 F.2d 936 (D.C. Circ. 1993) (reasonable accommodation of the relevant factors); *Wisconsin Electric Power Co. v. Fed. Energy Reg. Comm'n*, 602 F.2d 452 (D.C. Cir. 1979) (broad equitable latitude in fashioning refund orders).

Powerex, which supplied approximately one-third of CERS' PNW volumes, an average rate of $462 MW/h. This compares to a current mitigated price under the Commission's prospective market mitigation plan of $92 MW/h. (Pechman, CAL-14 at 5:14-17). By virtually any standard, the prices charged for power by most sellers resulted in windfalls.[279] The Commission has taken steps to mitigate the price and therefore provide some relief on a going-forward basis. Equity requires that refunds now be ordered retrospectively in order to correct the market dysfunctions that clearly occurred and permitted sellers to take advantage of buyers.

Additionally California Parties claim that ordering refunds will advance the Commission's goal of fostering markets that self-regulate in the future. As California Parties Witness Dr. Pechman explained, the ordering of refunds will establish a much-needed precedent for appropriate pricing behavior:

> At this point, the de-regulated power markets have no frame of reference as to what is "just and reasonable" pricing behavior. Refunds will establish precedent and begin to establish norms of behavior. These norms of behavior will form the basis of self-policing on the part of marketers and generators.
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> (CAL-14 at 20:16-21).

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[279] As Seattle Witness McCullough observed in rebuttal, the prices charged for electricity far outstripped increases in the component production costs, such as the cost of natural gas:

> Any party to the price excursions of the past eighteen months knows that the spark gap between electricity and gas climbed to unheard of levels after May 2000. Simply stated, an electric price shift of 1,000% cannot be explained by a gas price shift of 100%.
>
> (NPG-68 at 11).

California Parties further contend that the sellers argue that an order of refunds will retard investment in generation and slow down the process of recovery in the Western markets.[280] As California Parties' Witness Dr. Pechman explained in rebuttal, however, refunds will have no such effect. The mitigated prices that the Commission has already ordered on a prospective basis are more than sufficient to induce investment. As investment is based upon expectations of future prices, generators already know that the high prices they enjoyed during the period through June 2001 are irrelevant to future expectations. (CAL-14 at 4-6).

Powerex Witness Peterson suggested in his testimony that CERS gained a competitive advantage in the PNW by locating employees in the control room of the California ISO, the California Parties argue. (PWX-6 at 7). Counsel for Powerex pursued this issue vigorously on cross-examination of California Parties' Witnesses Hart and Green. As the record presently stands, however, this is now a non-issue. As explained by Mr. Hart and Mr. Green on cross-examination, during the time CERS employees were stationed at the ISO, they had no access to information in the ISO control room. (Tr. 831:3-9). They were segregated from ISO employees, seated facing away from everyone else in the control room, given blank screens on their computer consoles, and afforded no special access to information. Moreover, procedures were in place to prevent ISO employees from sharing information with CERS employees. (Tr. 976:4-20).

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[280] TFG Witness Jones, for example, argued that "Ordering refunds is adverse regulatory intervention in a process that was producing the very signals that would prevent future price spikes." (PPL-1 at 4:1-4).

Quite apart from the fact that the record in this case demonstrates that information is not shared between ISO and CERS employees, California Parties maintain, Powerex's insinuations ignore two fundamental realities. First, this record contains no evidence that ISO employees had information that could have been useful to CERS employees in negotiating bilateral contracts in the PNW.[281] Second, as a practical matter, CERS employees needed to be on-site at the ISO in order to determine, on an hour-by-hour basis, what transactions CERS needed to back the real time grid needs or "net short."[282] As Mr. Hart explained on cross-examination, CERS could not effectively arrange transactions on an hour-by-hour basis based on hour-by-hour ISO requirements other than through physical presence. CERS was "not set up electronically" to obtain the necessary information from the ISO for hourly transactions. (Tr. 975:3-16). Accordingly, none of the concerns articulated in the Commission's July 25 Order concerning CERS inter-

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[281] Given the volume of purchases CERS made from Powerex and the unrebutted testimony that CERS only purchased from Powerex as a last resort, it should be obvious that CERS did not have the benefit of "inside information" from the ISO that helped it to obtain more favorable prices.

[282] The role of CERS is to purchase power in order to "fill the gap" between power supplied by California's investor-owned utilities ("IOUs") and municipal utilities and the requirements of California electric consumers. Forecasts of the shortfall between supplies and demand are performed on a day-ahead, hour-ahead and "real time" basis, and the net shortfall (hence "net short") is purchased and supplied by CERS. On a "real time" basis, the ISO, as the clearinghouse, is the only entity in a position to know the quantity of the "net short" that CERS must meet.

actions with the ISO in the California market[283] have any application here.[284]

In addition, the California Parties contend that Powerex Witness Peterson suggests in his testimony that, because CERS was delegated "sole authority" to determine that its purchases were "just and reasonable" for flow-through purposes to consumers under California law, CERS already has conceded that all prices that it paid were "just and reasonable" for FPA purposes. (PWX-6 at 5-6). This is nonsense. CERS' determination of "reasonableness" of its own purchases under California law[285] focuses only on whether there were less costly alternatives—*i.e.*, whether wholesale power was available at a lower price. CERS makes no attempt to second-guess this Commission's judgment whether particular wholesale prices charged by sellers were "just and reasonable," nor could it do so. (Tr. 977:23-978:12). AB1x does not supplant this Commission's determination of what constitutes a "just and reasonable" rate.

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[283] 96 FERC ¶ 61,120, at p. 61,515.

[284] Counsel for Powerex also made much of the fact that Mr. Hart had not specifically instructed CERS employees concerning the Commission's Standards of Conduct for Transmission Providers. (Tr. 821:14-24). To begin with, these standards do not apply to CERS, which is not a transmission provider. (Tr. 974:19-20). In any event, as Mr. Hart testified, CERS employees and ISO employees were instructed to refrain from sharing information with each other:

> They were not given nor did they have access to any other information with respect to any information that the ISO would have had with respect to any bids or anything else.

(Tr. 827:19-21).

[285] California Water Code § 80110, added by AB1x-1, TFG-14.

The market dysfunction that manifested itself in California and the rest of the Western electricity market during 2000 and 2001 is a complex problem with multiple causes. Although it would be difficult (and perhaps futile) to attempt to trace the market dysfunction to a culpable party, the identity of the *beneficiaries* of the PNW market dysfunction could not be more clear. As pointed out by California Parties Witness' Dr. Pechman, refusing refunds to California consumers because of well-intentioned efforts at deregulation by California officials and the Commission simply blames the victims for a problem beyond their control. This problem was obvious to all market participants, and resulted in market power that enabled sellers to charge unjust and unreasonable prices to California consumers, the California Parties maintain. (CAL-14 at 15:1-16).

Additionally, the California Parties argue that Powerex cannot credibly maintain that it reasonably relied to its detriment on Mr. Hart's statement, that CERS would not seek refunds. *First*, as explained in Mr. Hart's rebuttal, Mr. Hart made it clear from the outset that, although CERS would not assert a claim, he could not speak for other California agencies who might seek refunds on behalf of consumers. (CAL-9 at 8:3-9). *Second*, at the time Mr. Peterson asked for the assurance, all participants in the PNW market were well aware that refunds were being discussed openly and considered by such parties as the California AG. (Tr. 973). Powerex does not claim that it ever attempted to secure any assurances from the California AG or other consumer representatives. *Third*, as the whole of Mr. Peterson's and Mr. Hart's testimony makes clear, Powerex's "no refund" assurance demand was fundamentally coercive. Powerex

was well-aware that CERS needed Powerex to help it "keep the lights on" in California. Such coercive behavior should not be rewarded by absolving Powerex of its obligation to pay refunds for the benefit of California consumers. *Fourth*, Powerex did not even ask for the "no refund" assurance until May 16, 2001, four months after it commenced sales to CERS, and only one month from the conclusion of the refund period, according to the California Parties. (PWX-6 at 19; CAL-9 at 8).

Staff:

Staff argues that it is undisputed that the Commission has the discretion to order refunds.

In the California proceedings, the Commission determined that all sellers of energy in the California ISO and PX spot markets, both public and non-public utility sellers, should be subject to refund liability for the applicable periods. The non-public utilities have filed numerous applications for rehearing of the Commission's determinations. During the course of the hearing the Presiding Judge denied a motion by the City of Burbank to certify the following question: "Whether, under Section 201(f) of the FPA, the Commission can exercise jurisdiction over non-public utilities' bilateral sales in the Pacific Northwest, which were outside of any "centralized" and "organized" ISO or PX spot market?" The Presiding Judge found: (1) that non-public utilities play a greater role in the PNW and their participation is essential to develop a record in this proceeding; (2) that the Commission previously decided to include non-jurisdictional entities in proceedings involving refunds; and (3) that the July 25 Order did not exclude non-jurisdictional facilities from the PNW proceeding.

As shown on Staff's Exhibit S-8, the total refund amount claimed by parties in these proceedings is $1,931,354,858. Other parties to this proceeding have advanced reasons why certain of the claims shown on Ex. S-8 should not be considered in the total amount because they are not refund claims,[286] are claimed by a California entity, or reflect all definitions of the spot market as shown on the template.

The definition of spot market as well as the inclusion or exclusion of the California claims, would affect the magnitude of refunds. For example, six non-California parties, Clark PUD, EWEB, Northern Wasco, City of Seattle, Port of Seattle, and City of Tacoma requested a total of approximately $461.5 million in refunds. This is based on total MWh of 1,892,072. If the spot market is narrowly defined as 24 hours or less, the total MWh for such transactions account for 4.15 percent of total MWh. Under Staff's proposed spot market definition of up to one month, the total MWh involved would be approximately 80 percent of the total. Similarly, in dollar terms, if the spot market is defined as 24 hours or less, then refunds for such transactions would amount to only 14.34 percent of total claimed refunds. If the definition is up to one month, such transactions would account for approximately 75 percent of total claimed refunds.

When California transactions (CDWR) are included in the refund analysis, the results shift to reflect the enormous number of California transactions and the

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[286] At the hearing, a representative for SMUD indicated that the claims outlined in its testimony of August 17, 2001 and reflected in Staff's Exhibit S-8, were more in the nature of counter-claims and ripple claims, rather than a direct claim for refunds. Tr. at 783-85, 1248.

fact that they are primarily 24 hours or less. California transactions of 24 hours or less account for approximately 6,691,706 MWh out of a total California claim of 6,802,944 MWh. Similarly, $1.45 billion of California's $1.46 billion refund claim is tied to transactions of 24 hours or less.

In terms of calculating refunds, Staff included in its template a column for the California ISO market clearing price. This column reflects hourly mitigated market prices as provided by the California ISO to Judge Birchman in the *San Diego* proceeding on August 9, 2001. These prices could be used as a potential starting point for calculating any refund claims. Staff notes, however, that the prices reflected on the template are subject to change pending Judge Birchman's certification of the California ISO data to the Commission and the Commission's further orders. Ex. S-3 at 9-10.

TFG:

On the other hand, the TFG asserts that refunds related to sales into PNW spot markets from December 25, 2000 through June 20, 2001 are unlawful under the Federal Power Act, are adverse to the public interest, and would be, in any event, impossible to administer. Intervenors cannot pursue their refund claims in this docket based on Puget's Complaint, which never related to refunds and was long ago abandoned by Puget. It is inappropriate for intervenors to substitute themselves for Puget and use this docket to launch retroactive refund claims.[287] Puget

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[287] This is particularly true here given that Puget's Complaint has been dismissed, *see* December 15 Order, 93 FERC at p. 62,020, a decision that the Commission has never vacated or modified.

is no longer prosecuting its Complaint for any purpose. Tr. at 727. Moreover, Puget's Complaint did not seek refunds and was limited to relief for sales "into" the PNW, not exports "out of" the PNW and "into" California.[288] Nonetheless, refund claimants, intervenors in this case, have attempted to expand the scope of the Puget Complaint and, as a consequence, the very record of the proceedings in this docket. As the Presiding Judge consistently ruled in this case, intervenors must "take the record as they find it."[289] By seeking relief beyond that sought by Puget, Tacoma, Seattle, the California Parties, and other claimants, have not taken the record as they found it, but have sought to dramatically alter and expand its nature and scope. The request for refunds under these circumstances violates the Commission's longstanding policy prohibiting intervenors from expanding complaints initiated by others. To the extent parties wish to prosecute claims beyond the scope of a complaint, such parties must initiate a new Section 206 proceeding.[290] In *Louisiana Power & Light*

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[288] Complaint at 1 n.1, 2, 10-12.

[289] *See supra* note 11 and orders cited therein.

[290] *See American Elec. Power Serv. Corp.*, 93 FERC ¶ 61,329, at p. 62,122 (2000) (rejecting a request for an Section 206 investigation that was made as part of a motion to intervene instead of in a separate request); *ISO New England, Inc., et al.*, 91 FERC ¶ 61,227, at p. 61,830 (2000) (determining that complaints must be filed separately); *Deseret Generation & Transmission Co-Operative*, 78 FERC ¶ 61,274, at p. 62,153 (1997) (request for an Section 206 investigation must be made separately in a complaint proceeding); *Arizona Pub. Svc. Co.*, 78 FERC ¶ 61,083, at p. 61,305 n.20 (1997) (the Commission's "consistent practice" is to reject Section 206 complaints that are filed in motions to intervene or protests). The Commission, in fact, will reject requests by parties on rehearing to treat their original

Company,[291] the Commission explained that it would not treat pleadings (motions, interventions) filed by third parties in a complaint proceeding initiated by another party as the complaint itself.[292] Allowing intervenors to prosecute a refund claim beyond the scope of the Complaint initiated by Puget and beyond the procedural path of that Complaint, including its withdrawal, will therefore improperly expand the function of intervenor to that of a complainant.[293]

According to TFG, the filed rate doctrine holds that the only rate that a regulated public utility may legally charge for its services is the one properly submitted to and made effective by the appropriate regulatory authority.[294] The doctrine protects the customer from illegal charges because it bars the utility from charging anything other than the filed

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protests as complaints. *See Entergy Services, Inc.*, 52 FERC ¶ 61,317, at p. 62,270 (1990).

[291] 50 FERC ¶ 61,040, at p. 61,062 (1990) ("*Louisiana Power*").

[292] *Id.* ("a complaint cannot be submitted as an integral part of a protest and a motion to intervene in an ongoing proceeding; *it does not allow interested parties sufficient notice of the complaint because it is not formally docketed and noticed*") (emphasis added).

[293] *E.g., Union Oil of California dba Unocal v. Cook Inlet Pipe Line Co.*, 73 FERC ¶ 63,006, at p. 65,040 (1995) (an intervenor and Commission Staff were prevented from raising issues in a proceeding and directed to raise such issues in a separate complaint filed with the Commission); *see Yankee Atomic Electric Company*, 60 FERC ¶ 61,316 (1992) (intervener free to file a separate complaint); *Nevada Power Company*, 70 FERC ¶ 61,391 (1995) (requiring that a complaint be filed with the Commission pursuant to Section 206 in a separate docket and where parties would be permitted an opportunity to respond).

[294] *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 (1981); *see also, e.g., Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246, 251-52 (1951).

rate. The utility too is protected in that its sales at the approved and published rate cannot be later challenged.[295] The "whole purpose" of the filed rate doctrine is to provide the "necessary predictability" to which industry participants are entitled prior to when, rather than after, their business decisions are made.[296]

The Commission observed in the July 25 Order that the filed rate doctrine applies to market-based rates, TFG argues.[297] Wholesale sales by TFG members into PNW markets are made pursuant to market-based rate schedules that each had filed with the Commission and which the Commission accepted. The market rules, (*i.e.*, the WSPP umbrella contract) constitute the mechanism for ensuring that the clearing prices under market-based rates are the product of lawful market forces.[298] In this case there is no claim that the rates charged by any TFG member

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[295] *Montana-Dakota Utilities Co.*, 341 U.S. at 254 (utility "can claim no rate as a legal right that is other than the filed rate, whether fixed or merely accepted by the Commission" and the Federal Power Act withholds "power to grant reparations"); *accord Maine Public Service Co. v. FPC*, 579 F.2d 659, 664, 667 (1st Cir. 1978) (under a final, filed rate, reparation can reach "neither past profits, nor past losses"); *Arizona Grocery Co. v. Atchison, Topeka & Santa Fe Railway Co.*, 284 U.S. 370, 384 (1932) (required to "render rates definite and certain, and to prevent undue discrimination," without exposure to reparations).

[296] *Towns of Concord v. FERC*, 955 F.2d 67, 71 (1992) (*citing Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 493 (D.C. Cir. 1985)).

[297] 96 FERC at p. 61,506.

[298] *New England Power Pool*, 90 FERC ¶ 61,141, at p. 61,425 (2000) (NEPOOL market rules are the filed rate); *NRG Power Marketing, Inc. v. New York Indep. Sys. Operator, Inc.*, 91 FERC ¶ 61,346, at p. 62,162 (2000) ("the ISO Market Rules are the filed rate").

ever violated the WSPP Agreement. Thus, TFG rates throughout this period were filed rates; they cannot be revised retroactively.

TFG argues that the only exception to the filed rate doctrine (here, the market rates charged under the WSPP contract) occurs when the Commission institutes an investigation under FPA Section 206 into the reasonableness of those rates and establishes a "refund effective date." Section 206(b) provides that "the refund effective date shall not be earlier than the date 60 days after the filing of [the complaint or notice of the Commission's intent to begin a Section 206 investigation] . . . nor later than five months after the expiration of such 60-day period."[299] The refund effective date provisions of Section 206(b) thus assure wholesale power sellers operating under filed rates that they will have formal advance notice, through the refund effective date, when their sales are subject to refund.[300]

According to TFG, the Commission has never established a refund effective date in this docket. Rather, the earliest indication to PNW wholesalers that their sales could be subject to refund occurred in the April 26 Order in Docket No. EL01-68-000, when the Commission opened a Section 206 investigation into WSCC sales "other than sales through the Cali-

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[299] *See also Southwestern Elec. Coop., Inc. v. Soyland Power Coop., Inc.*, 95 FERC ¶ 61,254, at p. 61,880 (2001); *UtiliCorp United Inc. v. City of Harrisonville*, 95 FERC ¶ 61,054, at p. 61,130 (2001).

[300] Even when a valid refund effective period can be established, however, the Commission retains discretion to deny Section 206(b) refunds unless in the public interest. November 1 Order, 93 FERC at pp. 61,379-61,380.

fornia ISO markets."[301] The order provided that the Commission would establish a refund effective date 60 days after publication of the notice of initiation of the WSCC investigation in the *Federal Register*. This notice was published on May 3, 2001.[302] Thus, the earliest possible refund effective date for the WSCC investigation (inclusive of the PNW) is July 2, 2001.

The consequence is that the putative refund period —December 25, 2000 through June 20, 2001—can never become effective. Puget's Complaint was dismissed by the Commission's December 15 Order, and cannot now be used to establish a refund effective date.[303] Nor could the Commission attempt to establish a refund effective date on rehearing of the December 15 Order since the five-month window specified in Section 206 (which began 60 days after the date of Puget's Complaint) for establishing such a prospective refund period cannot be established retroactively; only a refund effective date established within the

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[301] 95 FERC at p. 61,365.

[302] 66 *Fed. Reg.* 22223 (May. 3, 2001); *see also* June 19 Order, 95 FERC at p. 62,568.

[303] While Puget initially filed a request of rehearing of the Commission's rejection of its Complaint, Puget withdrew that rehearing request on June 22, 2001. Rule 216(b) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.216(b), provides that such motions for withdrawal become effective 15 days from filing if no motion in opposition is filed within that period or the Commission does not otherwise issue an order disallowing the withdrawal. The Commission issued no such order and, while motions in opposition were filed by some parties, no such parties were participants to the proceeding as required by Rule 212(a), 18 C.F.R. § 385.212(a). Accordingly, Puget's withdrawal of the rehearing request became effective as a matter of law on July 9, 2001.

five-month window under Section 206(b) can provide advance notice. Here, the five-month period expired on May 25, 2001 (Puget's Complaint was filed October 26, 2000). Even if these defects were not fatal to any claim for refunds (and they are), in no circumstances could refunds be associated with contracts executed prior to December 25, 2000. Exh. BPA-1 at 7-8. For these reasons, TFG contends it is legally impermissible, consistent with Section 206(b), for refunds to be ordered for any period relevant to this proceeding.

Additionally, TFG maintains, that the *Mobile-Sierra* doctrine bars refunds of prices negotiated in the PNW under bilateral contracts freely entered into by the complaining parties where, as here, refunds would be adverse to the "Public Interest." Even if the filed rate doctrine were not an absolute bar to ordering refunds in this proceeding (which it is), refunds are prohibited under the *Mobile-Sierra* doctrine for the vast majority of the spot sales at issue, which were performed under the WSPP Agreement and its service schedules.[304]

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[304] The record shows that the vast majority of PNW sales relevant to this proceeding, as well as the CDWR purchases, are performed under the WSPP umbrella contract. *See* Exh. S-3 at 7 (majority of transactions were made pursuant to the WSPP Agreement); *see also* Exhs. NPG-12, NPG-13, NPG-14, NPG-15, NPG-15a, NPG-15b. Several parties, in fact, have testified that *all* of their transactions at issue in this proceeding—including all of their sales to Seattle, Tacoma, *et al.*, in the PNW as well as those sold in California markets that are the subject of the claims made by the California Parties—were performed under the WSPP Agreement. *See, e.g.*, Exh. CP-1 at 3; Exh. CPS-1 at 2-3; Exh. PWX-6 at 9 (all transactions with CDWR are through the WSPP Agreement); Exh. IE-1 at 7.

The WSPP contract contemplates that all sales under its auspices are final and binding and not subject to abrogation by the Commission, TFG asserts. The WSPP Agreement describes "the legal principles that will control future power sales between the parties." It is based on bilateral trading, with participants using the WSPP standardized contractual terms and conditions to execute transactions. *See* Exh. NPG-74 at 6; Exh. ENR-1 at 10. As described by Staff, the WSPP Agreement is a standardized power sales contract, under which jurisdictional members sell electricity at market prices once they receive market-based rate authority from the Commission. *See* Exh. S-3 at 8:12-13 ("The WSPP Agreement provides that Parties are free to negotiate the specific terms and conditions of a transaction under the service schedules."). EWEB explains that its current WSPP contracts are "negotiated at arm's length between willing buyers and sellers." *See* Exh. NPG-68 at 6. This is effectuated through Schedule C, Section C-3.6 of the WSPP Agreement, which provides that the rates for electricity provided for power sold under its auspices would be at market rates negotiated by the parties. *See* Exh. S-6 at 88. While Section 6.1 of the WSPP Agreement provides that the parties to the contract may make "joint application" to the Commission under Section 205 of the FPA to change the rates agreed upon in the contract, the Agreement does not provide for review under FPA Section 206 by the Commission pursuant to unilateral action of one party to the contract, which is precisely what Tacoma, Seattle, the California Parties, and the other refund claimants are seeking to do. *See* Exh. S-6 at 12-13.

Under the *Mobile-Sierra* doctrine, the absence of a specific provision allowing unilateral changes in rates signifies an intent not to permit one party to the contract (including the instant complainants) to unilaterally seek a modification of the contract rate provisions under FPA Section 206, as would be the case here through retroactive refunds.[305] The *Mobile-Sierra* doctrine preserves the FPA's reliance on voluntarily negotiated contracts; arms-length sales under market-based rates are the quintessential example of such contracts. The D.C. Circuit has "repeatedly emphasized the importance of contractual stability in cases involving the *Mobile-Sierra* doctrine."[306] As settled contractual expectations play a crucial role in the scheme of the Act, before the Commission can modify the pricing provisions of a contract, it must demonstrate that the revision will serve a "public interest" beyond the just and reasonable requirement.[307]

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[305] *See San Diego Gas & Elec. Co. v. Pub. Svc. Co. of New Mexico*, 91 FERC ¶ 61,233, at p. 61,852 (2000); *see also Texaco Inc.*, 148 F.3d 1091, 1095-96 (D.C. Cir. 1998) (citations omitted); *Boston Edison Co. v. FERC*, 233 F.3d 60, 65 (1st Cir. 2000) (citations omitted).

[306] *See Potomac Elec.*, 210 F.3d at 409 (citations omitted).

[307] *See, e.g., Boston Edison*, 233 F.3d at 64-65; *Papago Tribal Utility Auth.*, 723 F.2d at 953. The burden is on the Commission and any party that seeks unilateral contract modification to make this showing. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667,709 (D.C. Cir. 2000) (emphasis added), *cert. granted sub nom., People of the State of New York and Public Serv. Comm. of the State of New York v. FERC*, 69 U.S.L.W. 3574 (U.S. Feb 26, 2001) (No. 00-568). The *Mobile-Sierra* Doctrine does not apply when parties to a contract expressly provide that the Commission may override the contract's provisions under Section 206's just and reasonable standard. *United Gas*

The "public interest" standard, which has been described by some Circuits as "practically insurmountable,"[308] is a much more stringent standard than can be met merely showing that the contract prices are "unjust and unreasonable" under of Section 206. In *Sierra*, illustrating what a utility must show in order to be relieved of an "improvident bargain" (a fixed-rate contract that was no longer profitable), the Supreme Court stated:

> the sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest—as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory. That the purpose of the power given the Commission by § 206(a) is the protection of the public interest, as distinguished from the private interests of the utilities, is evidenced by the recital in § 201 of the Act that the scheme of regulation imposed is "necessary in the public interest." When § 206(a) is read in the light of this purpose, it is clear that a contract may not be said to be either "unjust" or "unreasonable" simply because it is unprofitable to the public utility.[309]

Pipe Line Co. v. Memphis Light, Gas & Water Div., 358 U.S. 103 (1958). The market-based rate tariffs in the Pacific Northwest do not contain a *Memphis* reservation.

[308] *Papago Tribal Utility Auth.*, 723 F.2d at 954.

[309] *Sierra*, 350 U.S. at 355 (emphasis supplied); *see also Potomac Elec. Power Co.*, 210 F.3d. at 406 (*quoting Papago Tribal Util. Auth.*, 723 F.2d at 953 (citations omitted)); *see also, Northeast Util. Svc. Co.*, 55 F.3d at 691 (FERC can modify the terms of a contract under *Mobile-Sierra* where third parties are

According to TFG, none of the complainants testified that transactions arising under the WSPP Agreement have threatened their solvency, have cast upon consumers an excessive burden, or were unduly discriminatory.[310] To the contrary, the witness for the City of Tacoma conceded during the hearing that the WSPP Agreement provides substantial benefits to all potential purchasers in the PNW, and should be preserved intact and unchanged. *See* Tr. at 660, 661. Although the three factors listed in *Sierra* are not exclusive, and other factors can be used to demonstrate that the public interest is hurt, no showing in this regard has been made here.[311] In fact, the public interest factors shown on the record compel the opposite conclusion.

Additionally, TFG maintains, that the Commission already has approved the manner in which the PNW market functions, when it approved the WSPP Agreement. The content of that agreement is the product of a decisional process to which its 220 signatories, including claimants have subscribed. Changes are implemented according to a consensus process involving 90% of the members under the Agreement. Exh. IE-1 at 7. Now, rather than achieving the 90% consensus required to implement changes to that Agreement, the refund claimants are seeking ad hoc exceptions, supported by very few of the subscribers.

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threatened by possible "under discrimination" or the imposition of an "excessive burden." (citations omitted)).

[310] *See* Exh. NPG-67 at 8 (stating only that "refunds would simply create some measure of equity to parties that are disproportionately harmed.").

[311] *Northeast Util. Svc. Co.*, 66 FERC ¶ 61,332, at pp. 62,084-85 & nn. 65, 66, *reh'g denied*, 68 FERC ¶ 61,041 (1994), *aff'd*, 55 F.3d 686 (1st Cir. 1995).

If the parties to the WSPP Agreement cannot rely on the terms establishing finality of pricing of bilateral agreements, if they cannot rely on the provisions that require mutual consent for pricing changes, if they cannot rely on the consensus decisional process to which they agreed, then plainly they cannot rely on the Agreement itself.

The whole purpose of the Agreement was to establish a functioning and comprehensive market. The Commission cannot sensibly revise one provision retroactively at the request of select parties without destroying the core of the WSPP Agreement. Most certainly this is not consistent with the public interest, as discussed more fully in the following sections.

Moreover, according to TFG, refunds would be inconsistent with the Commission's goals to establish stable power markets. The Commission's April 26 Order sets rules for the California mitigation plan that establishes that market players will be able to operate, knowing that the rules will not continually change, and that prices will not be reset after-the-fact.[312] Retroactive changes are insidious and damaging to investors' confidence in the markets. Retroactive changes in a bilateral market inevitably cause a loss of confidence in the stability and predictability of the market.

Testimony presented by each of Drs. Jones and Tabors and Mr. Van Vactor concludes that a loss of confidence in the market will cause costs to consumers to increase, as market participants demand additional risk premiums and additional security for their transactions. *See* Exh. PPL-1 at 4:1-19, 15:3-6; Exh. PWX-1 at 10:5-10, 11:10-113, 12:6-13:4, 13:14-17; Exh.

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[312] April 26 Order, 95 FERC ¶ 61,115, at p. 61,352.

ENR-1 at 3:21-4:2; *see also* Exh. IE-1 at 11. Further, as shown by BPA's Mr. Oliver, regulatory interference will have a chilling effect on trading and would drive marketers out of the region, decreasing the number of market participants, diminishing market liquidity and adversely affecting reliability. A retroactive refund process is likely to result in a significant reluctance by many participants in the market to conduct transactions when prices are high, *i.e.*, in times of scarcity. Exh. BPA-1 at 23; Exh. PPL-1 at 7. These are the times when liquidity and competition are most required. Because spot market transactions are those for immediate delivery, they are exactly the kind of transactions which the Commission should insulate from the kind of challenges advanced in this case.

Market liquidity, with a large number of buyers and sellers and a large and diverse supply of products, is a key component of a well-functioning competitive market. Loss of liquidity will lead to greater price volatility in the future, particularly if combined with anemic investment in new capacity during an extended period of uncertainty. Introducing refund liability into a competitive market thus will decrease the number of market participants and increase prices. Refund claimants made no attempt to rebut this clear testimony as to the harm of refunds, TFG avers.

Further, TFG argues, if refunds are ordered and price caps are not market responsive, demand response will be discouraged and perhaps reversed. The PNW demand response has been exemplary in achieving economic efficiency in the market. Exh. PPL-1 at 5-15. Setting artificial caps or reimposing cost-of-service ratemaking is exactly the opposite of

what good public policy demands. *Id.*; Exh. PWX-1 at 9-18.

The April 26 Order also sought to "encourage, and not discourage, the critically needed investment in infrastructure."[313] A retroactive refund requirement will send warning signals to new investors that investment in this region is not secure and is subject to regulatory manipulation. Market signals to the supply side of the business, established at artificially low levels, will have the predictable effect of discouraging needed supply. To the extent that investors lose confidence in the market, capacity additions will evaporate. Given the nearly universal agreement that the western markets as a whole need substantial new capacity additions in the next several years, a loss of confidence and exit of investors is the very worst result that could be envisioned.

Moreover, TFG argues, that ordering retroactive refunds on the basis of a generic complaint will throw the certainty of market-based rates nationwide into disarray. On a more practical level, the TFG notes that it would be particularly destabilizing for the Commission to order retroactive refunds based solely on a generic complaint similar to the Puget Complaint. In most parts of the country, sellers with market-based rates have no price cap. If the Commission establishes a precedent that anyone filing a generic market complaint could qualify for refunds imposed retroactively, the entire wholesale electricity market could be chilled until any complaint, however spurious, is finally dismissed or resolved. Those who oppose competition—or who simply have negotiated uneconomic transactions for themselves—could un-

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[313] 95 FERC at p. 61,352.

ravel the competitive process by misuse of the complaint power. The reason for the notice requirements under Section 206 and the corresponding limitations on retroactive application are valid and should not, and legally cannot, be lightly disregarded. Thus, the Commission should be very careful in applying price mitigation retroactively and should tailor any refund liability as narrowly as possible. It should not extend its refund proceeding from California to the very different, and well-functioning, PNW marketplace.

Additionally, TFG asserts that granting refunds to the limited group of complainants would be inequitable. Requiring refunds will simply not produce equity. To the contrary, the record shows that refund claimants could have taken many actions to cover short positions with lower cost supply. They had options to build or to buy in the forward markets but voluntarily chose to over rely on the spot market, which they knew or should have known was highly volatile. There is simply no rational basis to allow refunds to compensate those market participants who made clearly voluntary and unrestricted choices while penalizing the vast majority of suppliers in the PNW who used the forward markets to achieve a balanced portfolio and lower costs. This, again, would produce a result precisely the opposite of the Commission's stated goals and would reward the very behavior it found objectionable in the California market.

Nor would refunds provide even short term benefits to the few market participants seeking them, TFG avers. The evidence made clear that "Nothing is more likely to drive potential sellers away from a buyer than a re-trade. This business relies on finality of deals and reliance on your trading partner."

Exh. IE-1 at 10. Balancing the short-term benefit of refunds to a few market participants against the immediate and long-term damage to the market and to future investment decisions, it is impossible to reconcile refunds with the overall public interest standard. It would be arbitrary and capricious and a reversal of all of its stated tenets for the Commission to attempt to justify refunds in the circumstances surrounding the PNW.

TFG additionally argues that refunds for transactions in the bilateral market are impossible as a matter of fact. Ripple claims have been excluded from this preliminary proceeding, however, they are a major impediment to a rational refund order.[314] Putting aside all other considerations, it would be simply impossible to identify and quantify the amount of refunds potentially owed by all parties in the PNW under virtually any plan. The scope and magnitude of ripple claims, the time that would be required for such claims to be determined, and the inability to identify or recover claims from certain parties precludes ordering refunds for bilateral transactions in the PNW.[315]

Complicating matters further, any particular spot transaction may have originated from a portfolio including a mix of short-term and long-term transactions. Exh. PWX-1 at 16. As Dr. Tabors explains, depending on the level of mitigation imposed, "the

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[314] Order on Ripple Refund Claims, Docket No. EL01-10-000 (August 23, 2001) (Presiding Judge acknowledged that "It is apparent that there was a chain of buyers and sellers in connection with many, if not most of the spot market bilateral transactions that are the subject of this proceeding."); *see also* Exh. PWX-1 at 13-17; Exh. BPA at 21-22.

[315] *See generally* Order on Ripple Refund Claims.

ripple could (and likely would) eventually touch every transaction that took place in the WSCC for the period of December 25, 2000 through June 20, 2001." Exh. PWX-1 at 16 (emphasis added). The sheer magnitude of this potential ripple liability is enough to cause the Commission to reject the possibility of refunds in this proceeding.

The immense number of potential ripple claims is directly related to the highly active nature of the PNW wholesale electricity market. As Dr. Tabors explains, electricity in the PNW region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain. Exh. PWX-9 at 7. Powerex alone estimates that it engaged in approximately 30,000 transactions during the period from December 25, 2000 through June 20, 2001 PWX-9 at 6. Dr. Tabors conservatively estimates, and the NPG does not challenge, that approximately 500,000 transactions would have to be recalculated based on a refund order in the PNW. Exh. PWX-1 at 17. Given the sheer magnitude of contracts that would have to be rewritten as a result of imposing refunds, it would be impossible to unwind fairly the chain of transactions that resulted in a single bilateral sale between December 25, 2000 and June 20, 2001.

Putting the magnitude of potential ripple claims aside, as a factual matter it may be impossible for purchasers to recover ripple liability given the large number of sellers in the PNW that are not subject to the Commission's jurisdiction and the inability to trace upstream sellers in every transaction. Exh. BPA-1 at 22. Most, if not all, buyers and sellers purchase and sell from a portfolio of resources. Whereas in some instances a "back-to-back" purchase and sale

(identical in volume, price, terms and conditions) is made and respective buyers and sellers can be identified, in many instances a particular seller's resource portfolio is an aggregate of a wide variety of supply rights which may include ownership or contractual rights to generation output, long and short-term contracts with other marketers, options, and even rights to call for demand reductions negotiated at a price with load users. Further, if some type of arbitrary hourly price were used as a refund benchmark, parties would have to be permitted to offset sales at this retroactive price cap with sales below this cap. Exh. BPA-1 at 19. In these situations, it would be nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision. As a result, Mr. Oliver testified that even if all potential ripple claims could be identified, only a fraction of the transactions actually would be adjusted, leaving certain parties to shoulder the brunt of refunds. *Id.* at 21-22. It would take a protracted evidentiary proceeding to begin unraveling the multiple waves of ripple claims. *Id.*; Exh. BPA-1 at 22; Exh. PWX-1 at 15-17.[316]

TFG maintains that extending this proceeding to examine ripple claims would thus introduce a considerable level of regulatory risk and unfairness into every subsequent transaction, thereby disrupting PNW markets to an unacceptable extent. Exh. BPA-1 at 23; *see also* Exh. PPL-1 at 7; Exh. PWX-1 at 18. This uncertainty and risk will require sellers in all transactions to raise prices, representing a risk premium, and may even cause sellers to abandon the market entirely. Exh. PWX-1 at 17-18; Exh. BPA-1 at 23; Exh. PPL-1 at 7. As has already begun to hap-

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[316] *See id.*

pen in California, investment in additional generation will be discouraged as potential investors question whether the market will be sufficiently stable to provide for a return on their investment. Exh. CHPUD-1 at 6.

Finality of transactions, according to TFG, is a fundamental requirement of a vibrant, sustainable electricity market. Requiring parties to unwind past transactions and rewrite complete contracts "remove[s] all faith in the wholesale electric market." Exh. PWX-1 at 17. Unleashing the ripple claims would thus spiral the PNW market down a rabbit-hole from which it will not recover for many years. For this reason alone, the Presiding Judge should recommend to the Commission that refunds not be ordered in this proceeding, and that this entire matter be terminated with prejudice.

"Book-Out" transactions are outside the scope of this proceeding, TFG contends. Refund claimants also have attempted to include financial "book-out" transactions in this proceeding, contradicting clear precedent that such transactions are not even subject to the Commission's jurisdiction. *See, e.g.*, Exh. NPG-67 at 10-11. As the spot market includes only transactions for immediate delivery, by definition the spot market cannot include financial "book-out" transactions.[317] Since book-outs do not result in the physical delivery of electricity at any time, much less in the immediate spot market, such transactions cannot fall within the definition of spot market or the scope of

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[317] Book-out transactions are transactions that, for a variety of reasons (such as the presence of transmission constraints or offsetting purchase and sale transactions), do not result in physical delivery of electricity. These transactions are instead settled financially.

this proceeding. The inclusion of book-out transactions also cannot be reconciled with clear precedent that book-out transactions are not subject to the Federal Power Act in the first instance.[318] Book-outs do not, and, therefore, are not subject to Commission jurisdiction.[319] Accordingly, no claim of refunds for book-out transactions is properly before the Commission.

Bonneville/BPA:

BPA's Vice President for Bulk Power Marketing, Stephen R. Oliver, testified, that as a practical mat-

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[318] Commission precedent on this issue is clear—the Commission has asserted jurisdiction only over those transactions that result in the physical delivery of electricity. The Commission has jurisdiction under Sections 205 and 206 of the Federal Power Act only where three conditions are present: where "[(i)] the electricity futures contract goes to delivery, [(ii)] the electric energy sold under the contract will be resold in interstate commerce, [(iii)] and the seller is a public utility." *New York Mercantile Exchange*, 74 FERC ¶ 61,311, at p. 61,987 (1996) ("*NYMEX*"). *See also* Exh. PSCO-1 at 7:9-16 (*citing Morgan Stanley Capital Group*, 69 FERC ¶ 61,175, at p. 61,696 (1994), *clarified, Englehard Power Marketing, Inc.*, 70 FERC ¶ 61,250, at p. 61,778, *order on reh'g*, 72 FERC ¶ 61,082, at pp. 61,436-37 (1995)).

[319] This position is fully consistent with the Commission's electricity sales reporting requirements. All electric utilities, including power marketers, must report each year to the Commission their jurisdictional electric power transactions on the Commission's Form No. 582. The Commission has addressed the question of book-out transactions with regard to its Form 582 reporting requirements. *Annual Charges Under the Omnibus Budget Reconciliation Act (CNG Power Services, et al.)*, 87 FERC ¶ 61,074 (1999) ("*CNG Services*"). In *CNG Services*, the Commission clarified that book-out transactions need not be reported in Form 582, stating "the parties need to report on their Form Nos. 582 only those transactions that result in the *delivery* of electric energy." *Id.* at p. 61,303 (emphasis added).

ter only a limited number of the transactions at issue in this proceeding could ever be adjusted if the Commission were to attempt to order refunds. BPA-1, at 21. In addition, BPA is very concerned that the precedent set by an order by the Commission for refunds in the Pacific Northwest for the relevant time period could result in reliability problems in the region if sellers, as a consequence, hesitate to conduct transactions when prices begin to rise. *Id.* at 23. However, if the Commission does order refunds, the refund calculation must credit sellers for transactions below the mitigated market-clearing price, whatever that might be. BPA-1 at 19.

Even if the Commission were to adopt a relatively narrow definition of spot market bilateral sale, BPA believes it would be impossible to identify and calculate the amount of refunds that would be owed by all sellers in the Pacific Northwest. Because there is not a centralized spot market used for serving native load requirements in the Pacific Northwest, as there is in California, unwinding these transactions will be virtually impossible. BPA-1, at 22. As Judge Cintron correctly noted in the Order on Ripple Claims, dated August 23, 2001:

> [f]rom the factual record already compiled and the representations of the parties to me, it is apparent that there was a chain of buyers and sellers in connection with many, if not most of the spot market bilateral transactions that are the subject of this proceeding. Accordingly, the number of refund claims that could develop in each successive ripple could become very large.

Order at 2 (mimeo).

Indeed, BPA testified that many of these transactions are multi-layered, complicating the ability to

successfully identify and effectively unwind the transactions. BPA-1, at 22. For example, BPA made numerous remarketing sales of power that became available due to reduction in the operations of a number of its direct service industrial (DSI) customers during the relevant period, at prices negotiated by the DSI customer. BPA was obligated under contracts it entered into with many of these DSIs in 1995 to either credit the power bills of such DSIs by the amount of the revenues from such remarketing sales, or make cash payments to the DSI if the credit would exceed the amount owed by the DSI to BPA under its wholesale power bill. BPA-1, at 11. The sales of remarketed power made by BPA to Seattle City Light and the remarketing sale to Clark PUD are examples of such transactions. BPA-1, at 10-12; BPA-2 at 4-6. The remarketing transactions with Seattle are the subject of a refund claim against BPA, notwithstanding the fact that revenues associated with those sales were ultimately paid by BPA to a DSI customer. BPA-1, at 10. If revenues credited or paid by BPA to DSI customers are subject to refund, either with respect to the claims made in this proceeding or as part of any ripple claims, it is not clear that any DSI customer will have the financial ability to refund monies already earmarked and committed for employee compensation or power resource development. *Id.* at 21.

In addition, entities that purchased remarketed power may be tagged with refund obligations as downstream sellers of that power. *Id.* at 22. Certainly, notwithstanding the fact that BPA made the power sales on the DSI customers account, BPA should not and cannot be made to refund the revenues associated with those sales paid to the DSI

customers. Seattle's claim against BPA in this proceeding seeks exactly that result.

In addition, many participants in the market took steps, including BPA, to mitigate or avoid the high costs of transactions during the relevant period. *Id.* These efforts included expenditures for long-term forward purchases at prices influenced by the spot market, undertaking conservation measures, and curtailment efforts all of which are outside the scope of this proceeding. Given the vast nature of the problem and the limitations of the solution being undertaken here, the Commission should not attempt to order refunds in this proceeding because to do so would only provide partial equity which will undoubtedly compound the problems of the past winter for many market participants.

Perhaps most importantly, because so many sellers in the Pacific Northwest are non-jurisdictional entities, and therefore not subject to a Commission refund order, even if all the transactions implicated in any refund order could be identified and calculated, many of them ultimately will not be part of the refund equation. As a consequence, only some parties will shoulder the brunt of any refunds. BPA-1, Oliver at 22.

In addition, BPA contends that ordering refunds in the Pacific Northwest could result in regional reliability problems. BPA-1, at 23. The potential for refunds in the future is likely to result in a significant reluctance by many participants in the market to conduct transactions when prices are high. *Id.* The Prepared Answering testimony of Mr. Philip Movish challenges BPA's observation that reliability may suffer if the Commission orders refunds. NPG-60, at 13. Mr. Movish suggests that with the Commission's

mitigation measures in place, there should be no need for future refunds. *Id.*

However, BPA's position on this issue is not a conclusion of economic theory based on the ineffectiveness of the Commission's mitigation measures, but rather a practical business observation by BPA's witness based on actual hands-on experience operating in the Pacific Northwest electric power markets, including the spot markets. Mr. Movish concedes that he lacks such experience, and in preparing his testimony did not consult with any traders that are actively trading in the Pacific Northwest. Hearing Tr. at 740:8-17. In fact, hesitancy to conduct business in the electricity market without a great deal of certainty about the sustain ability of the transaction will be particularly dangerous during emergency situations when supply is tight and prices tend to be higher. BPA-1, at 23. Because electricity transactions often occur during real-time, almost on an instantaneous basis, if parties hesitate to conduct transactions then reliability issues may arise. *Id.* Testimony filed on behalf of the Transaction Finality Group similarly concludes that introducing refund liability into the Pacific Northwest electric power markets will decrease the number of market participants and increase prices. PPL-1, Jones at 4:1-19; at 15:3-6. PWX-1, Tabors at 10:5-10; at 11:10-113; at 12:6-13:4; at 13:14-17. ENR-1, Van Vactor at 3:21-4:2. BPA agrees with the conclusion drawn in this testimony that a loss of confidence in the market will cause costs to consumers to increase, as market participants either exit the market, or demand additional risk premiums and additional security for their transactions.

However, if the Commission elects to order refunds in the Pacific Northwest, sellers should be credited for transactions that are both above and below the mitigated market-clearing price. Logic dictates that if purchasers claim refunds for charges above the mitigated market clearing price, they should also pay the difference between the mitigated clearing price and the price paid. BPA-1 at 19. Part of the underlying theory behind these refund claims is an attempt to replicate a transparent market. Under this theory, in a transparent market there would be a price at which all sales would be made during a specific period of time. Sellers and buyers should get the benefits of any attempt to replicate the market-clearing price. Therefore any methodology in the Pacific Northwest should include both upward and downward adjustment to the mitigated market-clearing price. *Id.*

Recommendations

The Commission dismissed Puget's complaint in the December 15 order. Puget filed a petition for rehearing of this decision. The Commission has not acted on this rehearing request. On July 24, 2001, Puget filed to withdraw its complaint and rehearing request. In the July 25 decision the Commission stated it would consider Puget's withdrawal request after this hearing. Based on the evidence developed in this case I recommend that the Commission affirm its decision to dismiss the complaint and grant the motion to withdraw. Puget is no longer prosecuting its Complaint for any purpose. Tr. at 727. I agree with TFG that intervenors cannot pursue their refunds requests based on a dismissed complaint and a complaint which Puget has sought to abandon. Moreover, as discussed in issue number one, above, Puget's complaint sought prospective remedy only.

The request for refunds under these circumstances violates the Commission's longstanding policy prohibiting intervenors from expanding complaints initiated by others. *See, e.g., Louisiana Power & Light Company*,[320] (the Commission held that it would not treat pleadings (motions, interventions) filed by third parties in a complaint proceeding initiated by another party as the complaint itself.) Allowing intervenors to prosecute a refund claim beyond the scope of the Complaint initiated by Puget and beyond the procedural path of that Complaint, including its withdrawal, will therefore improperly expand the function of intervenor to that of a complainant. Therefore, the December 25, 2000 cannot be the refund effective date. If the Commission reverses its dismissal, Puget's motion to withdraw will need to be addressed. If further proceedings are ordered in this case, the applicability of the Sierra Mobile doctrine to the specific claims against bilateral transactions entered under the WSPP Agreement would have to be determined. In this proceeding, refund claimants have not established any of the exceptions of the Sierra Mobile doctrine, in order to be entitled to modification of contractual terms under the public interest standard.

Evidence of record indicates that refunds would have a negative impact to the Pacific Northwest market. Testimony presented by each of Drs. Jones and Tabors and Mr. Van Vactor concludes that a loss of confidence in the market will cause costs to consumers to increase, as market participants demand additional risk premiums and additional security for their transactions. *See* Exh. PPL-1 at 4:1-19, 15:3-6;

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[320] 50 FERC ¶ 61,040, at p. 61,062 (1990) ("*Louisiana Power*").

Exh. PWX-1 at 10:5-10, 11:10-113, 12:6-13:4, 13:14-17; Exh. ENR-1 at 3:21-4:2; *see also* Exh. IE-1 at 11. Further, as shown by BPA's Mr. Oliver, regulatory interference will have a chilling effect on trading and would drive marketers out of the region, decreasing the number of market participants, diminishing market liquidity and adversely affecting reliability. A retroactive refund process is likely to result in a significant reluctance by many participants in the market to conduct transactions when prices are high, *i.e.*, in times of scarcity. Exh. BPA-1 at 23; Exh. PPL-1 at 7. These are the times when liquidity and competition are most required. Because spot market transactions are those for immediate delivery, they are exactly the kind of transactions which the Commission should insulate from the kind of challenges advanced in this case. Furthermore, the April 26 Order also sought to "encourage, and not discourage, the critically needed investment in infrastructure." A retroactive refund requirement will send warning signals to new investors that investment in this region is not secure and is subject to regulatory manipulation. Market signals to the supply side of the business, established at artificially low levels, will have the predictable effect of discouraging needed supply. To the extent that investors lose confidence in the market, capacity additions will evaporate. Given the nearly universal agreement that the western markets as a whole need substantial new capacity additions in the next several years, a loss of confidence and exit of investors is the very worst result that could be envisioned. I am not persuaded by the arguments advanced by the California Parties attempting to contradict this testimony.

I agree with TFG that refunds would not provide even short term benefits to the few market participants seeking them. The evidence indicates that "Nothing is more likely to drive potential sellers away from a buyer than a re-trade. This business relies on finality of deals and reliance on your trading partner." Exh. IE-1 at 10. Balancing the short-term benefit of refunds to a few market participants against the immediate and long-term damage to the market and to future investment decisions, it is impossible to reconcile refunds with the overall public interest standard.

BPA agrees with TFG in this regard. Exh. BPA-1 at 23. Mr. Philip Movish challenges BPA's observation that reliability may suffer if the Commission orders refunds. NPG-60, at 13. Mr. Movish suggests that with the Commission's mitigation measures in place, there should be no need for future refunds. *Id.* However, BPA's claims that its position on this issue is not a conclusion of economic theory based on the ineffectiveness of the Commission's mitigation measures, but rather a practical business observation by BPA's witness based on actual hands-on experience operating in the Pacific Northwest electric power markets, including the spot markets. Mr. Movish concedes that he lacks such experience, and in preparing his testimony did not consult with any traders that are actively trading in the Pacific Northwest. Hearing Tr. at 740:8-17. In fact, hesitancy to conduct business in the electricity market without a great deal of certainty about the sustain ability of the transaction will be particularly dangerous during emergency situations when supply is tight and prices tend to be higher. BPA-1, at 23. Because electricity transactions often occur during real-time, almost on

an instantaneous basis, if parties hesitate to conduct transactions then reliability issues may arise.

The evidence in this case also shows that determining the number of transactions subject to refunds would be a very complex task. The immense number of potential ripple claims is directly related to the highly active nature of the PNW wholesale electricity market. As Dr. Tabors explains, electricity in the PNW region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain. Exh. PWX-9 at 7. Powerex alone estimates that it engaged in approximately 30,000 transactions during the period from December 25, 2000 through June 20, 2001. PWX-9 at 6. Dr. Tabors conservatively estimates, and the NPG does not challenge, that approximately 500,000 transactions would have to be recalculated based on a refund order in the PNW. Exh. PWX-1 at 17. Given the sheer magnitude of contracts that would have to be rewritten as a result of imposing refunds, it would be impossible to unwind fairly the chain of transactions that resulted in a single bilateral sale between December 25, 2000 and June 20, 2001.

Moreover, the evidence shows that as a factual matter it may be impossible for purchasers to recover ripple liability given the large number of sellers in the PNW that are not subject to the Commission's jurisdiction and the inability to trace upstream sellers in every transaction. Exh. BPA-1 at 22. Most, if not all, buyers and sellers purchase and sell from a portfolio of resources. Whereas in some instances a "back-to-back" purchase and sale (identical in volume, price, terms and conditions) is made and respective buyers and sellers can be identified, in many instances a particular seller's resource portfolio is an

aggregate of a wide variety of supply rights which may include ownership or contractual rights to generation output, long and short-term contracts with other marketers, options, and even rights to call for demand reductions negotiated at a price with load users. Further, if some type of arbitrary hourly price were used as a refund benchmark, parties would have to be permitted to offset sales at this retroactive price cap with sales below this cap. Exh. BPA-1 at 19. In these situations, it would be nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision. As a result, Mr. Oliver testified that even if all potential ripple claims could be identified, only a fraction of the transactions actually would be adjusted, leaving certain parties to shoulder the brunt of refunds. *Id.* at 21-22. It would take a protracted evidentiary proceeding to begin unraveling the multiple waves of ripple claims. *Id.*; Exh. BPA-1 at 22; Exh. PWX-1 at 15-17.[321]

For instance, BPA made numerous remarketing sales of power that became available due to reduction in the operations of a number of its direct service industrial (DSI) customers during the relevant period, at prices negotiated by the DSI customer. BPA was obligated under contracts it entered into with many of these DSIs in 1995 to either credit the power bills of such DSIs by the amount of the revenues from such remarketing sales, or make cash payments to the DSI if the credit would exceed the amount owed by the DSI to BPA under its wholesale power bill. BPA-1, at 11. The sales of remarketed power made by BPA to Seattle City Light and the remarketing

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[321] *See id.*

sale to Clark PUD are examples of such transactions. BPA-1, at 10-12; BPA-2 at 4-6. The remarketing transactions with Seattle are the subject of a refund claim against BPA, notwithstanding the fact that revenues associated with those sales were ultimately paid by BPA to a DSI customer. BPA-1, at 10. If revenues credited or paid by BPA to DSI customers are subject to refund, either with respect to the claims made in this proceeding or as part of any ripple claims, it is not clear that any DSI customer will have the financial ability to refund monies already earmarked and committed for employee compensation or power resource development. *Id.* at 21.

I recommend that book out transactions not be part of this proceeding. I agree with TFG that "book out" transactions are not part of this proceeding.

Summary

Prices in the PNW during the period 12/25/00-6/20/01 were the result of a number of factors, the shortage of supply, excess demand, drought, increased price in natural gas along with the price signals from the California markets. The PNW is a competitive market and has been for a long time. The transactions involved in this proceeding resulted from bilateral agreements between the parties. Under these circumstances the prices were not unreasonable or unjust and refunds should not be ordered in this proceeding. I recommend the proceeding be terminated by affirming the December 15 dismissal of Puget complaint and allowing Puget to withdraw its rehearing request.

Proposed Findings of Fact

1) The PNW is defined by the Pacific Northwest Electric Power Planning and Conservation Act.

2) Southbound wholesales of power at the California-Oregon border ("COB") and the Nevada-Oregon Border ("NOB") are not within the PNW for purposes of this case, because the delivery point is not to a PNW load server and deliveries actually take place in California.

3) The PNW is uniquely dependent upon hydroelectric power since approximately 80 percent of the region's generation capacity by fuel type is hydroelectric.

4) Although the California and PNW markets are closely interrelated, they are characterized by important and fundamental differences:

California handles spot market transactions through a centralized clearinghouse while PNW uses bilateral contracts to consummate spot market sales.

California relies primarily upon fossil fueled generation, while the Pacific Northwest relies predominantly upon hydropower.

5) For purposes of this proceeding, spot market transactions in the PNW comprise all sales for 24 hours or less that are entered into one day in advance or, before weekends, holidays, or WSCC scheduler conferences, up to 48 hours in advance, and within the month and balance of the month transactions executed during the period December 25, 2000 through June 20, 2001 with PNW delivery points to serve loads within the PNW.

6) The PNW market is dominated by forward contractual hedging and little spot market activity.

7) Bilateral spot market sales of electricity in the PNW are negotiated at arms-length between willing

buyers and sellers and ordinarily reflect circumstances unique and specific to the seller and buyer.

8) During the relevant period, spot market sales in the PNW were made pursuant to bilateral agreements entered into by the parties to the transactions, typically pursuant to the terms of the Western Systems Power Pool Agreement.

9) The WSPP Agreement is a default standardized contract for electric power sales and physical options.

10) The WSPP comprises more than 220 members.

11) The WSPP Agreement applies to transactions between WSPP members.

12) Three basic products sales are covered by the WSPP Agreement: Economy Energy Service (Service Schedule A), Unit Commitment Service (Service Schedule B) and Firm Sales/Exchange Service (Service Schedule C).

13) Utilities that purchase electricity to serve load in the PNW can assemble a portfolio of long, medium, and short-term contracts in order to minimize their exposure to volatile spot market prices.

14) During the relevant period, the PNW power market, including the market for bilateral spot transactions, performed as a competitive market.

15) Suppliers of electricity into the PNW are numerous.

16) There are a very large number of actual and potential competitors in the power sales market in the PNW.

17) In 2000 and 2001, power supply shortages relative to demand affected prices in the west.

18) Temperatures in the early winter of 2000-01 in the PNW were colder than normal.

19) In November and December 2000 precipitation in the PNW remained at record low levels.

20) During the 2000-2001 period, the PNW experienced its worst drought in 50 years.

21) Price increases in the PNW during the relevant period, reflect shortages in water supplies, weather, and natural gas prices. The traditional trading patterns between California and its northern neighbors —electricity shipped from the PNW to California in the summer and returned by California to the PNW in the winter—failed in the winter of 2000-01 because California had no surplus electricity to offer to northwest utilities in that winter.

22) In September 2000, Powerex offered to sell electricity under forward contracts for the first quarter of 2001 at $75.50 and $81 per megawatt hour.

23) For several years preceding the relevant period, wholesale electricity prices in the PNW were relatively quite low.

24) Hedges for spot price volatility existed during the relevant period in the Pacific Northwest in the form of bilateral forward, futures, over-the-counter forward contracts, and self-build options also existed before and during the relevant period.

25) CDWR's purchases during the potential refund period were at market-based rates under the WSPP Agreement.

26) CDWR makes purchases solely for California loads. It does not make purchases for consumers outside of California.

27) CDWR does not maintain offices or conduct operations in the PNW. CDWR does not contract for transmission in the PNW.

28) CDWR's purchases were made at four interconnect points on the boundary of the PNW and California: COB, the NOB, Summit and Cascade. In the case of the COB and NOB interconnect points, CDWR took delivery at substations located within California.

29) All but a *de minimis* number of CDWR's bilateral transactions during the potential refund period involved purchases from the PNW, and not sales into the PNW.

30) CDWR's transactions for which the California Parties claim refunds are not within the scope of Puget Sound Energy's October 26, 2000 Complaint in Docket No, EL01-10.

31) CDWR is not an intervenor in this proceeding.

32) Refund claims with respect to CDWR's bilateral purchases are being asserted by the "California Parties" (the Attorney General of the State of California, the California Electricity Oversight Board and the California Public Utilities Commission).

33) The California Parties claim $1,465,632,884 in refunds with respect to bilateral purchases by CDWR, and the payback in kind of 361,165 MWh in energy delivered by CDWR to PNW counterparties under exchange arrangements ($46,612,654) (a total of $1,512,213,967 including the exchange transactions).

34) CDWR is not seeking refunds in this proceeding.

35) The California Parties have failed to show why all of CDWR's bilateral transactions are not subject to the July 25 Order wherein the refund claims for bilateral contracts by CDWR were rejected by the Commission, in Docket Nos. EL00-95 *et al.*

36) There is no basis for considering the California Parties' refund claims in Docket No. EL01-10. There is no need for further proceedings with respect to these claims in connection with this PNW proceeding, and these claims should be dismissed from Docket No. EL01-10, as being beyond the scope of this proceeding.

37) Any "sleeved" transaction, exchanges or aggregation arrangements and "booked-out" transactions are outside the scope of this proceeding.

38) The preponderance of the evidence establishes the lack of exercise of market power by any seller in the PNW.

39) Only seven PNW purchasers out of a universe of 220 members of the Western Systems Power Pool ("WSPP") are asking the Commission to award them refunds: City of Seattle $278,000,000; City of Tacoma $65,407,755; Port of Seattle $9,371,660; Northern Wasco People's Utility District $44,089,364; Eugene Water and Electric Board $39,719,000; Sacramento Municipality Utility District $4,587,511 and Clark Public Utilities $64,080,603.

40) The total volume of spot market bilateral sales in the PNW for the period December 25, 2001 through June 20, 2001 is likely higher than the volumes shown on the confidential data submissions of August 16, 2001 (certified to the Commission as part of the record in this proceeding) since data was not received from all sellers.

41) There is no indication from approximately 75 percent of WSPP members of whether or not they participated in the PNW spot market during the relevant time period.

42) Most of the sales transactions reported in the data submissions were made pursuant to the standard WSPP agreement.

43) The rights of all parties to assert an entitlement to refunds for bilateral spot market purchases in the PNW in the event that such party is ordered to pay refunds have been preserved.

44) Prices for approximately 500,000 bilateral spot market transactions will have to be reset if all purchasers eligible for refunds assert their right to receive refunds. These are the so-called "ripple" claims.

45) As a factual matter, it may be impossible for purchasers to recover their ripple refund claims because of the difficulty in tracing upstream sellers in every transaction.

46) The jurisdictional reasoning that underlies the assertion of refund authority over power sales of non-public utilities to the California ISO and Power Exchange markets in the July 25 order, in Docket EL00-95, does not apply to bilateral power sales of non-public utilities in the Pacific Northwest.

47) Puget Sound's complaint was dismissed by order dated December 15, 2000. No other section 206 complaint has been filed by any party to this proceeding. Thus, no refund effective date has been established for ordering refunds in this proceeding.

48) The parties have failed to show that market-based prices charged in the PNW during the potential refund period were unjust and unreasonable.

FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Docket Nos. EL01-10-000, EL01-10-001, EL01-10-007, and EL01-10-009

Order Granting Rehearing, Denying Request to Withdraw Complaint and Terminating Proceeding

(Issued June 25, 2003)

Before Commissioners: Pat Wood, III, Chairman; William L. Massey, and Nora Mead Brownell.

1. In this order, we grant Puget Sound Energy Inc.'s (Puget's) request for rehearing of our December 15, 2000 order[1] (December 15 Order) in which we dismissed Puget's complaint asking the Commission to prospectively implement a region-wide price cap for wholesale sales of energy or capacity into the Pacific Northwest. The relief that Puget requested has already been provided in our June 19, 2001 order (June 19 Order), which prescribed price mitigation in the electricity spot markets throughout the West.[2]

2. In addition to Puget's request for a prospective price cap, certain participants in the proceeding

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[1] *San Diego Gas & Electric Co., et al.*, 93 FERC ¶ 61,294, at p. 62,019 and Ordering Paragraph (K) (2000).

[2] *San Diego Gas & Electric Co., et al.*, 95 FERC ¶ 61,418 (2001), *order on reh'g*, 97 FERC ¶ 61,275 (2001), *order on reh'g*, 99 FERC ¶ 61,160 (2002), *appeal sub nom. Public Utilities Comm. of the State of California, et al. v. FERC*, Nos. 01-71051 *et al.* (9th Cir. June 29, 2001 and later).

(Puget not included) sought to expand the complaint proceeding and the requested remedy. They sought retroactive refunds for spot market bilateral sales in the Pacific Northwest. Based on the totality of the circumstances presented, including the large number of sellers and magnitude of transactions in the Northwest and the fact that the majority of sales that took place are not within our jurisdiction, the Commission concludes that appropriate relief was provided by institution of the West-wide mitigation plan in June 2001 and that the equities do not justify refunds. With regard to the request for refunds, the record established in the preliminary evidentiary hearing before Presiding Administrative Law Judge (ALJ) Cintron in this proceeding[3] demonstrates that it is not possible to fashion an equitable remedy that would do justice to all the participants in the Pacific Northwest electricity spot markets. Our reasoning on this difficult set of circumstances is discussed at length later in the order.

3. This order benefits customers because it will provide greater certainty and stability in the Pacific Northwest electricity spot markets.

Background

Puget Sound Energy Complaint

4. On October 26, 2000, Puget filed a complaint petitioning the Commission for an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy or capacity under the Western Systems Power Pool (WSPP) Agreement, may sell energy or capacity into the Pacific North-

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[3] *Puget Sound Energy, Inc., et al.*, 96 FERC ¶ 63,044 (2001) (*ALJ Recommendations*).

west's wholesale power markets.[4] Puget made clear that it was only seeking prospective relief in the form of a price cap. Yet, it also requested that "to the extent any refund is called for in response to [Puget's] petition, [Puget] respectfully requests that the refund effective date be set, in accordance with Section 206 of the Federal Power Act (16 U.S.C. § 824e(b)), sixty (60) days after the date of filing of this Complaint."[5]

5. The Commission dismissed Puget's complaint in the December 15, 2000 Order.

6. Puget sought timely rehearing of that order on January 12, 2001. Subsequently, on June 22, 2001, Puget submitted a motion to dismiss its complaint and a notice of withdrawal of its complaint and its subsequent rehearing, explaining that the Commission's June 19 Order satisfied its complaint because it implemented price mitigation measures on wholesale sales throughout the West.

7. Several entities filed answers to Puget's motion. Amongst them, the City of Seattle opposed the motion and argued that the proceeding should be kept open because non-California market participants have paid prices that are unjust and unreasonable, and because retaining the proceeding would permit the Commission greater flexibility in determining the scope and effective date for refunds. The City of Tacoma and Port of Seattle opposed Puget's motion for similar reasons.

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[4] Puget stated that, for purposes of its complaint, "Pacific Northwest" has the meaning set forth in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14) (2002).

[5] Puget Complaint at para. 17.

8. On June 22, 2001, unaware of Puget's motion filed on the same day, the Commission issued an order clarifying that parties in the settlement proceedings related to what has come to be known as the "California refund proceeding," Docket No. EL00-95 *et al.*, could also discuss a settlement related to sales in the Pacific Northwest.

The July 25 Order

9. In a July 25, 2001 order (July 25 Order), the Commission noted that, according to the Chief Judge's Report in the settlement discussions (mentioned above), there was little time to address the issues raised by the Pacific Northwest parties.[6] These parties did not have data on what they claimed they were owed, or on an amount of refunds due them, and certain parties filed comments requesting additional process to document the harm suffered and to engage in meaningful settlement discussions with affected sellers. The July 25 Order then stated:

> In light of the complexities associated with these retroactive bilateral calculations and the absence of any further development of this issue in the settlement proceeding, and in recognition that the prior settlement proceeding focused primarily on California, we will establish a separate preliminary evidentiary proceeding pertaining to the Northwest. The proceeding is intended to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific

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[6] *San Diego Gas & Electric Company, et al.*, 96 FERC ¶ 61,120, at p. 61,520 (2001).

Northwest for the period beginning December 25, 2000 through June 20, 2001.[7]

10. The Commission explained that December 25, 2000, 60 days after Puget filed its complaint, is the earliest refund effective date the Commission could establish for Puget's complaint if the Commission determined that it was appropriate to deny Puget's motion to withdraw the complaint and, further, to grant rehearing of the Commission's previous dismissal of the complaint. The Commission, however, did not set the complaint for hearing under FPA Section 206 or establish a refund effective date in the July 25 Order. The Commission also stated that it would decide at a later time, after completion of the preliminary evidentiary hearing, whether to grant Puget's request to withdraw the complaint.

Preliminary Evidentiary Hearing and the ALJ's Recommendations

11. The preliminary evidentiary hearing was conducted before Presiding Judge Cintron during three days in early September 2001.

12. On September 24, 2001, the ALJ issued her recommendations and proposed findings of fact. She concluded that the proper definition of the Pacific Northwest bilateral sales spot market included "all sales for 24 hours or less that are entered into one day in advance or, before weekends, holidays, or WSCC scheduler conferences, up to 48 hours in advance, and within the month and balance of the month transactions . . . ."[8] Further, she adopted the definition of "Pacific Northwest" set forth in the

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[7] *Id.*

[8] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,386. *See also id.*, at p. 65,331.

Pacific Northwest Electric Power Planning and Conservation Act.

13. The ALJ recommended to the Commission that no refunds are warranted for wholesale power sales made in the Pacific Northwest between December 25, 2000 and June 20, 2001.[9] In essence, she concluded that evidence demonstrates that the Pacific Northwest market for spot sales of electricity was competitive and functional during the relevant period of time, and because prices were not unreasonable.[10] The ALJ found that, while California electric energy prices affected electric energy prices in the Pacific Northwest, prices in the region were driven up by a combination of factors, including reduced available power due to drought, increased demand, and relatively high natural gas prices.

14. In making her determination, the ALJ noted the differences between the California and Pacific Northwest power markets. While "inextricably interrelated," she said the California and Pacific Northwest wholesale power markets differ greatly in that California has a centralized spot market with a single auction price, while the Pacific Northwest's spot market operates through individually negotiated, bilateral contracts and relies heavily on hydropower. Besides Pacific Northwest utilities relying more heavily on forward contracts, the ALJ commented that demand in the Pacific Northwest is more elastic than in other parts of the West due to the presence of aluminum smelting and other energy-intensive industries in the region.[11]

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[9] *Id.*, at p. 65,370.

[10] *Id.*, at p. 65,367.

[11] *Id.*, at p. 65,336.

15. The ALJ also noted that Pacific Northwest utilities have numerous supply options, including self-supply and purchases on spot and forward markets.[12] Pacific Northwest utilities had the ability to reduce their exposure to volatile spot market prices by assembling a portfolio of long-, medium- and short-term contracts. Thus, she found that the paid prices were the result of arm's-length negotiations and reflected the value that willing buyers and sellers placed on those transactions in the face of supply constraints. The ALJ blamed "market fundamentals, exacerbated by financial uncertainty and confusion" as the cause of Pacific Northwest's high power prices, and stated that "the evidence shows that the Pacific Northwest performed just as workably competitive markets would under adversity."[13]

16. Having found that rates were not unjust and unreasonable in the Pacific Northwest during the relevant period of time, the ALJ did not make findings regarding the price and volume of sales in the Pacific Northwest or the appropriate methodology for determining potential refunds.[14] Rather, she recommended that, since Puget Sound is no longer pursuing its complaint and requested withdrawal from the proceeding, and only intended to seek prospective remedies, the Commission affirm the December 15, 2000 order dismissing the Puget complaint and allow Puget to withdraw its rehearing request.

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[12] *Id.*, at pp. 65,368-69.

[13] *Id.*, at p. 65,367.

[14] The ALJ identified the total extent of potential refunds claimed to date as $1.9 billion based on the claims asserted by eight parties to the proceeding. *Id.*, 96 FERC at p. 65,336.

17. Parties that filed briefs on exception are identified in Appendix A.

100-Day Evidence Proceeding

18. In a December 19, 2002 order (December 19 Order), the Commission, acting on motions to reopen the evidentiary record, allowed parties in the proceeding to conduct additional discovery for the period January 1, 2000 to June 20, 2001.[15] The December 19 Order also stated that parties had until February 28, 2003 to submit directly to the Commission "additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001, and proposed new and/or modified findings of fact."[16] In a February 10, 2003 Order, the Commission allowed parties an opportunity to respond to the February 28 submissions.[17] In a sub-

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[15] *Puget Sound Energy, Inc., et al.*, 101 FERC ¶ 61,304 (2002).

[16] *Id.* at P 11.

[17] *Puget Sound Energy, Inc., et al.*, 102 FERC ¶ 61,163 (2003) (February 10 Order). The City of Tacoma, Washington and The Port of Seattle filed a request for clarification or, in the alternative, rehearing of the February 10 Order. They argued that, pursuant to fundamental due process rights, the Commission should allow parties the opportunity to respond to new material filed on March 20, 2003. In fact, the March 20 pleadings were reply comments, filed in response to new evidence and proposed new findings of fact filed by Tacoma, the Port and other parties seeking refunds. Thus, Tacoma and the Port seek an opportunity to file and answer to an answer, which is not permitted by our Rules. 18 C.F.R. § 385.213(a) (2003). Moreover, the opportunity to submit further responsive pleadings is at the discretion of the Commission. *E.g., Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc.*, 435 U.S. 519, 543-46 (1978). Accordingly, we deny the request for clarification or, in the alternative, rehearing of Tacoma and the Port.

sequent order, the Commission extended the filing deadline until March 3, 2003, with reply comments due by March 20.[18]

19. Clark Public Utilities (Clark) and Californians for Renewable Energy (CARE) filed testimony one day late. In addition, Clark filed a request for clarification, as directed by the Bankruptcy Court administering the Kaiser Aluminum bankruptcy, that Clark could file testimony on the issue of the appropriate definition of "spot market."

Oral Argument

20. On May 6, 2003, the Transaction Finality Group (TFG) filed a request for oral argument before the Commission regarding the legal factual and policy issues raised in the proceeding. Oral argument was held before the Commission on June 2, 2003.

Discussion

A. *Procedural Matters*

1. *Late Filings*

21. For good cause shown, we accept Clark's late filing in the 100-day evidence proceeding based on its explanation that (1) it was delayed by the Bankruptcy Court's ruling on the afternoon of March 3, 2003, which required Clark to revise its filing; (2) Clark started the electronic filing process prior to the close of business on March 3; and (3) the filing one day late will not prejudice any party to this proceeding because Clark served its filing on all parties on March 3. However, we deny Clark's request for clarification, and will not accept new testimony (which

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[18] *San Diego Gas & Electric Co., et al.*, 102 FERC ¶ 61,194 (2003).

Clark filed under seal) related to the appropriate definition of spot market.

22. CARE offered no explanation for its late filing, and it is accordingly rejected. Further, it appears that CARE has not intervened in this proceeding.

2. *Puget's Motion to Withdraw its Pleadings*

23. The Commission dismissed Puget's complaint in the December 15, 2000 Order and Puget filed for rehearing; on July 24, 2001, Puget filed to withdraw its complaint and rehearing request, but several motions opposing the withdrawal were timely filed and the Commission has not yet acted on that withdrawal.[19] The ALJ recommends that the Commission affirm its decision to dismiss the complaint and grant the motion to withdraw. Since the original complainant has no interest in pursuing its claim, this proceeding arguably could be terminated on this basis alone. If so, intervenors would not be able to pursue their refund requests based on a dismissed complaint which the complainant seeks to abandon.

24. Furthermore, Puget's original complaint sought refunds only as a prospective remedy. The ALJ remarks that she agreed with the Transaction Finality Group's view that, "[b]y seeking relief beyond that sought by Puget, Tacoma, Seattle, the California Parties, and other claimants have not taken the re-

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[19] Puget argues that its petition to withdraw was granted by operation of law since no party to the proceeding objected and the Commission failed to act within 15 days. But this argument is incorrect since several non-parties filed timely objections to Puget's petition. Rule 216 does not state that the motion opposing the notice of withdrawal must be filed by a party. In any event, these non-parties also moved for late intervention, which was subsequently granted, making them parties to the proceeding.

cord as they found it, but have sought to dramatically alter and expand its nature and scope. The request for refunds under these circumstances violates the Commission's longstanding policy prohibiting intervenors from expanding complaints initiated by others. To the extent parties wish to prosecute claims beyond the scope of a complaint, such parties must initiate a new Section 206 proceeding."[20]

25. Although this case could be dismissed solely on procedural grounds, we decline to do so. There are a number of other cases before us that involve questions of refunds and questions about whether to reform contracts. It would be unfair to the parties of the Pacific Northwest to use these procedural issues to avoid addressing their concerns. Further, as the City of Seattle points out, intervenors that are now seeking refunds could have filed separate complaints with the Commission but instead reasonably relied on the Puget complaint, which raised similar issues, as an appropriate forum for addressing their overlapping claims. After allowing intervenors to pursue a preliminary hearing through the Puget complaint until now, it would be unfair to deny relief based on procedural issues and leave them with no other forum to pursue their complaints. The refund effective date under a new Section 206 complaint would not capture the relevant time frame.

26. Accordingly, we deny Puget's motion to withdraw its pleadings.

B. *Puget's Request for Rehearing*

27. The December 15, 2000 Order explained that "we will decline to adopt a region-wide price cap at

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[20] *ALJ Recommendations*, 96 FERC ¶ 63,044, at pp. 65,376, 65,383-84.

this time" because "there are no organized electricity markets outside of California to which a price cap could be applied since the majority of transactions that occur in the region do so on a bilateral basis."[21] The Commission dismissed the Puget complaint, stating that a region-wide price cap "is impracticable given the market structure in the Northwest, nor has the burden of proof been met to justify such an action."[22]

28. In its request for rehearing, Puget argued that California and the Pacific Northwest are part of an integrated wholesale market and that a soft cap order can be implemented for wholesale power sales even where there is no single price auction mechanism.

29. The Commission grants rehearing. While the Commission in the December 15, 2000 Order denied Puget's requested relief "at this time," the Commission several months later directed its Staff to conduct an investigation of the reasonableness of the rates for wholesale sales of electricity in the spot markets in the Western Systems Coordinating Council (WSCC).[23] Based upon the conclusions of Staff in its investigation, the Commission in the June 19 Order implemented price mitigation measures on wholesale sales throughout the West. The Commission directed that during reserve deficiency hours, when reserves in California fall below seven percent, the California

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[21] December 15 Order, 93 FERC ¶ 61,294, at p. 62,019.

[22] *Id.*

[23] *San Diego Gas & Electric Co., et al.*, 95 FERC ¶ 61,115 (2001) (April 26 Order). In April 2002, the WSCC and other Western councils merged to form the Western Electric Coordinating Council.

Independent System Operator (ISO) marketing clearing price would apply as the maximum price to all sales in the WSCC spot markets.[24]

30. In granting Puget's request for rehearing, we determine that the relief requested by Puget in its complaint was provided by the June 19, 2001 Order. Puget sought a prospective price cap, as was granted in our June 19 Order. As mentioned above, while Puget did not directly seek refunds for a prior period, it did ask the Commission to set a refund effective date. While we technically may have authority to require refunds for at least a short prior period,[25] we find that refunds would be inequitable for reasons explained below.

C. *Commission Determination Regarding Refunds*

31. The Commission instituted the preliminary evidentiary hearing in this proceeding to "facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001."[26] In this regard, we consider the hearing and the efforts expended by participants in developing a record on the matter worthwhile and helpful in assisting the Commission in understanding the Pacific Northwest spot market and the proper action to be taken in this proceeding.

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[24] June 19 Order, 95 FERC ¶ 61,418, at pp. 62,546-47, 62,556.

[25] The statute dictates that the Commission could set a refund effective date, at the earliest, of December 25, 2000, 60 days after the date that Puget filed its complaint. The latest refund effective date would be five months after the 60-day period, or May 26, 2001. 16 U.S.C. § 824e(b) (2000).

[26] July 25 Order, 96 FERC ¶ 61,120, at p. 61,520.

32. The Presiding ALJ found based on the evidence – and we believe that it is beyond question – that electricity prices in the region "rose dramatically" during the relevant period.[27] While there is no evidence in the record of dysfunction in the Pacific Northwest spot market itself, or the presence of market power in the Pacific Northwest spot market,[28] the ALJ determined that dysfunctions in the spot markets operated by the ISO and California Power Exchange (PX) affected the prices in the Pacific Northwest.[29] This latter finding is consistent with our previous determinations that recognize the integrated nature of the Western markets.[30] However, the ALJ found – and we agree that the record establishes – that other factors related to supply and demand fundamentals contributed to the dramatic prices in the region.[31]

33. As discussed above, in its June 19 Order, the Commission instituted prospective price mitigation measures:

> the Commission here is instituting a two-part approach to price mitigation for spot markets to cover all hours for California and the WSCC. Because these markets are integrated, the mitigation proposals must establish the same prices for all markets in order to prevent arbitrage where power is

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[27] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,367.

[28] *Id.*, at p. 65,370.

[29] *Id.*, at pp. 65,367, 65,369.

[30] December 15 Order, 93 FERC ¶ 61,294, at pp. 61,357-58; June 19 Order, 95 FERC ¶ 61,418, at pp. 62,547, 62,556.

[31] *ALJ Recommendations*, 96 FERC ¶ 63,044, at pp. 65,366-69 (discussing the supply and demand conditions that contributed to high prices).

diverted from the lower priced market to the higher priced. The mitigation plan further has to recognize the differences between the California market, which has an organized auction, and the remainder of the WSCC, which does not have a similar centrally organized market. The plan adopted by the Commission is tailored to provide a uniform scheme of mitigation that at the same time recognizes the differences between these markets.[32]

34. While Western power prices had begun to decline after the issuance of the April 26 Order,[33] the implementation of the West-wide mitigation plan resulted in a further "moderation" in electricity spot market prices.[34] Thus, the mitigation plan provided the relief requested by Puget, and on a forward basis the relief sought by other participants in the complaint proceeding.

35. What remains, however, is the claims for refunds during the potential legal window for refunds in the proceeding. Based on the record established in the preliminary evidentiary hearing, the Commission concludes that, even if prices were unjust and unreasonable, it is not possible to fashion a remedy that

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[32] June 19 Order, 95 FERC ¶ 61,418, at p. 62,556.

[33] *See id.*, at p. 62,546.

[34] *ALJ Recommendations*, 96 FERC ¶ 63,044, at 65,368. Both refund claimants and TFG agree that prices moderated in June 2001, although they disagree on the cause. TFG explained that prices "returned to normal levels" due to market forces such as a significant drop in consumption, a return to normal weather and new generation coming on-line. *Id.* Refund claimants contend that the market correction that occurred in late June 2001 resulted from the implementation of the Commission's mitigation plan. *See, e.g.*, California Parties' Post-Hearing Comments at 11.

would be equitable to all the participants in the Pacific Northwest market. The circumstances of this proceeding prevent an even and fair allocation of refunds, if they were found to be warranted. We elaborate below on the considerations that lead us to this conclusion.

1. *Governmental Entities*

36. The ALJ concluded that the rationale previously used by the Commission to assert jurisdiction over certain transactions of governmental entities in the California refund proceeding, Docket No. EL00-95, does not apply to the Pacific Northwest bilateral spot market because of differences between the Pacific Northwest and the markets operated by the ISO and PX.[35] The Commission agrees with the ALJ's conclusion on this issue.

37. Governmental entities are not subject to the jurisdiction of the Commission.[36] However, the Commission determined that "under the specific circumstances presented" in the California refund proceeding, it could properly assert Section 206 jurisdiction over certain transactions of governmental entities.[37] The Commission explained that it has jurisdiction over the subject matter of sales made into the organized power markets of the ISO and PX, both entities established under Commission authority and Commission-approved market rules. It also noted that all sellers in the organized markets agreed to accept the same clearing price for any given sale.

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[35] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,370.

[36] *See* FPA Section 201(f), 16 U.S.C. § 824(f) (2000).

[37] July 25 Order, 96 FERC ¶ 61,120, at pp. 61,511-13.

38. In contrast, the ALJ in the current proceeding found that the Pacific Northwest has never had a centralized power exchange and has no central clearing price, and energy is bought and sold continuously on a bilateral basis with each utility free to choose how to meet its firm load requirements.[38] Lacking such centralized markets in the Pacific Northwest, the Commission does not have authority over the rates of the governmental entities. Accordingly, under the conditions present in the Pacific Northwest during the relevant time frame, the Commission does not have FPA Section 206 jurisdiction over governmental entities' transactions and could not compel refunds for the transactions at issue in this proceeding.[39]

39. A large portion of the power bought and sold in the Pacific Northwest is by governmental entities,

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[38] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,365.

[39] Nor does the application of the West-wide mitigation plan to governmental entities provide a basis for directing governmental entities to make refunds in the Pacific Northwest proceeding. In the June 19 Order, the Commission invoked its conditioning authority and explained that, as a condition of selling into the ISO's markets and as a condition of using the ISO's interstate transmission grid, all sellers located in the WSCC, including governmental entity sellers, must abide by the West-wide price mitigation plan. *Id.*, 95 FERC ¶ 61,418, at p. 62,570. The Pacific Northwest complaint, in contrast, does not involve a prospective condition on wholesale sales, nor does it involve a market operated and controlled by a Commission-jurisdictional entity such as the ISO. Moreover, on rehearing, the Commission reversed its earlier determination and stated that the price mitigation measures set forth in the June 19 Order do not apply to governmental entities in the West outside of California's organized markets. *San Diego Gas & Electric Co., et al.*, 97 FERC ¶ 61,275, at p. 62,252.

including the largest seller in the region, BPA.[40] Moreover, the record establishes that electricity in the Pacific Northwest region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain.[41] Government entities, like most market participants in the Pacific Northwest, were both buyers and sellers in the region. Since the Commission lacks authority to impose refund obligations on sales by governmental entities in the present circumstances, "the burden of paying refunds will fall on a limited class of jurisdictional sellers in the region; and the benefit of receiving refunds will be available only to buyers who bought from those same sellers."[42] This result is inequitable and unbalanced. Moreover, the handful of parties that are asserting refund claims in this proceeding are all governmental entities. It would not do justice to allow these parties to receive refunds for their high-priced purchases while they are exempt from providing refunds for any high priced sales they may have made.

2. *Refunds Would Unfairly Reward Entities That Relied on the Spot Market*

40. The ALJ found that purchasers in the Pacific Northwest had numerous options in developing a portfolio of power supply and for years have been free to enter into short, medium, and long-term contracts

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[40] Exh. BPA-1 at 3 (BPA's sales account for 40 percent of the electric power consumed in the Pacific Northwest). *See also* Joint Post-Hearing brief of City of Tacoma, Port of Seattle and Wasco, at 45, describing BPA as the "predominant power marketer" in the region.

[41] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,384, citing Exh. PWX-9 at 7.

[42] *Id.*, at p. 65,370.

to achieve a hedged and balanced portfolio.[43] These options, including hedge instruments, remained available leading up to and during the time period at issue.[44] The ALJ also found that Pacific Northwest utilities were "generally forewarned" of potential supply shortages, noting that in 1999 BPA had expressed concerns about a potential energy deficit in the region.[45]

41. According to the ALJ, City of Tacoma accepted the risk of high spot market prices when it chose to sell its interest in the Centralia generation plant based on "environmental risk associated with the operation of the coal burning [Centralia] plant."[46] The City of Seattle also sold its share in this generation plant. As the ALJ explained:

> [i]f the position of the refund claimants is accepted, they would be relieved of the consequences of their conscious economic decisions at the expense of a functioning competitive market in which a vast majority of the [Pacific Northwest] purchasers during this period accept responsibility for the choices they made. For instance, Seattle recognized in September, 2000 that the Centralia sale left it "more dependent on the market than we have been historically." Exh. PPL-1 at 21 n. 10.[47]

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[43] *Id.*, at p. 65,366, citing Exhibits NGP-74 at 6, PWX-1 at 16, 21.

[44] *Id.*, at pp. 65,368-69, citing Tr. at 656-657, 689-90; Exhibit IE-2 at 14.

[45] *Id.*, at p. 65,367.

[46] *Id.*, at pp. 65,343, 65,368, citing Exh. NPG-57 at 3.

[47] *Id.*, at p. 65,368.

42. The current proceeding only concerns spot transactions, and not long-term sales and purchases in the Pacific Northwest. Thus, it would be unfair and inequitable to allow those market participants that relied heavily on the spot market to receive refunds, while those who perhaps more prudently engaged in a procurement strategy that included a higher balance of long-term instruments would not receive refunds.[48] As two State Commissions note, utilities that bought power in longer-term markets are unfairly punished since they would not receive refunds, but might be obligated to pay refunds for power purchased in the longer-term markets that was later sold in short-term markets.[49]

43. Given these findings of the ALJ, which the Commission adopts, we conclude that it would be inequitable to allow refunds in this proceeding.

3. *Allowing Refunds Would have Adverse Consequences to the Market*

44. The State Commissions are concerned that allowing refunds would effectively "rewrite" the rules on which buyers and sellers in the Pacific Northwest reasonably relied. This would "undermine the credibility of the regulatory process and could jeopardize

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[48] In December 2000, the Commission warned market participants, "those who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases." December 15 Order, 93 FERC at p. 61,996.

[49] October 29, 2001, Post-Hearing "Joint Comments" filed by the Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission (State Commissions) at 3-4.

investment" in energy infrastructure that could ultimately undermine service to retail customers.[50]

45. Likewise, the ALJ concluded that evidence indicates that refunds would have a negative impact on the Pacific Northwest market.[51] She describes testimony and other evidence to the effect that the ordering of refunds in the particular conditions that existed in the Pacific Northwest would cause a loss of confidence in the market, have a chilling effect on trading, cause costs to customers to increase as market participants demand additional risk premiums and additional security for their transactions, create a hesitancy to conduct business in times of scarcity, and discourage investment in needed infrastructure.[52] The ALJ concluded that refunds "would not provide even short-term benefits to the few market participants seeking them as the evidence indicates that 'Nothing is more likely to drive potential sellers away from a buyer than a re-trade. This business relies on finality of deals and reliance on your trading partner.'"[53]

46. The Commission adopts the ALJ's proposed findings and recommendations on this issue.

4. *Ripple Claims*

47. The ALJ concluded that because of the highly active nature of the Pacific Northwest wholesale electricity market, there would be an immense number of transactions subject to refund in this case.[54] It was

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[50] State Commissions' Joint Comments at 4.

[51] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,384.

[52] *Id.*

[53] *Id.*, quoting Exh. IE-1 at 10.

[54] *Id.*, at pp. 65,384-85.

estimated that electricity in the region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain, and that approximately 500,000 transactions would have to be recalculated if refunds are required in this case.[55] The ALJ determined that all parties reserved their rights to pursue claims if the Commission was to direct further proceedings to determine refunds.[56]

48. The volume of transactions involved in the bilateral spot market in the Pacific Northwest during the relevant time period is massive and would require prolonged time and effort to unravel. More importantly, we are concerned that, in the end, a fair result would not be achieved.

49. The ALJ explained that "[t]he evidence shows that . . . it may be impossible for purchasers to recover ripple liability given the large number of sellers in the PNW that are not subject to the Commission's jurisdiction and the inability to trace upstream sellers in every transaction . . . ."[57] Further, she found that, because most buyers and sellers purchase and sell from a portfolio of resources, and in many instances a particular seller's resource portfolio is an aggregate of a wide variety of supply rights, "it would be nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision."[58]

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[55] *Id.*, at p. 65,385.

[56] *Id.*, at p. 65,300.

[57] *Id.*, at p. 65,385. *See also* Proposed Finding of Fact No. 45 ("as a factual matter, it may be impossible for purchasers to recovery their ripple refund claims because of the difficulty of tracing upstream sellers in every transaction").

[58] *Id.*

50. As we have discussed above, since many of the buyers and sellers in the Pacific Northwest are governmental entities, there will be few chains of transactions that will not contain a non-jurisdictional transaction, which would effectively drop the burden of the refund into the lap of the last downstream jurisdictional transaction in the chain. On top of the practical difficulty of determining the chains of transactions, this would unfairly concentrate the burden of those claims on the jurisdictional sellers. Such an outcome is not equitable.

5. *Other Considerations*

51. The Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission all agree that this proceeding should be terminated and that the Commission should direct its attention to prospective mitigation measures.[59] Based on many of the same considerations that we have articulated above, these State Commissions are concerned that, regardless of whether bilateral spot market rates were unjust and unreasonable in the region during the relevant time period, refunds would not remedy the injuries caused by such rates and would not produce an equitable and balanced outcome for all affected buyers and sellers. Rather, "refunds would only serve inequitably to redistribute that damage."[60] We give due respect to the position of these State agencies, given their responsibility to protect many of the ultimate customers of energy in the region from unjust prices.

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[59] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,370. *See also* October 29, 2001, Post-Hearing "Joint Comments" filed by the State Commissions.

[60] State Commissions' Joint Comments at 3.

52. Finally, we take note that, of the hundreds of market participants in the region,[61] and of the estimated 500,000 transactions that occurred in the region during the relevant period of time, only a handful of entities have chosen to pursue claims for refunds in this proceeding.[62] While the ALJ determined that all parties reserved their rights to pursue claims if the Commission was to direct further proceedings to determine refunds, most market participants have chosen not to pursue such claims but would rather end the matter without further proceedings. Most telling, at oral argument, Pinnacle West explained that, although it was a net purchaser of power during the period at issue, it does not want a refund in this proceeding but, like most other participants, "wants this case to end and want[s] to move on."[63]

Conclusion

53. Based on the totality of the circumstances as we have described above in some length, we conclude that, even if prices were unjust and unreasonable,

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[61] During the relevant period of time, there were 226 members of the WSPP. *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,370. Of this number, only 56 members complied with the ALJ's requirement to provide transaction data required by the ALJ, *id.* at 65,353, and only eight chose to pursue claims, leaving us to conclude that the others' unwillingness to participate or respond reflects an unwillingness to change their contracts.

[62] The ALJ identifies eight claimants, several of which would be eliminated if we were to adopt the ALJ's recommendations regarding the appropriate definition of "Pacific Northwest spot market" and the region defined as the "Pacific Northwest" for purposes of this proceeding. *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,336.

[63] June 2, 2003, Oral Argument Trans. at 73.

the directing of refunds in this proceeding would not result in an equitable resolution of the matter.[64] Accordingly, we will not require refunds and terminate this matter without further proceedings.

The Commission orders:

(A) Puget Sound Energy, Inc.'s request to withdraw its complaint and request for rehearing is hereby denied, as discussed in the body of this order.

(B) Puget Sound Energy Inc.'s request for rehearing is hereby granted, as discussed in the body of this order.

(C) This proceeding is hereby terminated, as discussed in the body of this order.

Commissioner Massey dissented with a separate statement attached.

Commissioner Brownell concurred with a separate statement attached.

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[64] *See Heckler v. Cheney, et al.*, 470 U.S. 821, 831 (1985) (an agency's decision not to enforce is generally committed to an agency's absolute discretion); *Towns of Concord, Norwood, and Wellesley, Massachusetts v. FERC*, 955 F.2d 67, 72-74 (D.C. Cir. 1992) (Commission's broad discretion includes authority to determine that it would be inappropriate in a particular case to provide a remedy); *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967) (where the Commission exercises its remedial authority, its discretion is "if anything, at zenith").

APPENDIX A

Briefs on Exception

Alcoa, Inc.

Atofina Chemicals, Inc., Columbia Falls Aluminum Company and Golden Northwest Aluminum, Inc.

Bonneville Power Administration (BPA)

California Parties (The People of the State of California, Ex rel. Bill Lockyer, Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission)

City of Seattle

City of Tacoma, Washington; the Port of Seattle, Washington; and Northern Wasco County People's Utility District (collectively "Tacoma")

Clark Public Utilities

Commission Trial Staff

Duke Trading and Marketing L.L.C.

El Paso Merchant Energy, LP

Eugene Water & Electric Board

Kaiser Aluminum & Chemical Corporation

Merchants Serving DWR/CERS or "Merchants" (Mirant Americas Energy Marketing, LP; Powerex Corp.; TransaAlta Energy Marketing (U.S.), Inc.; TransCanada Energy Ltd; and Williams Energy Marketing and Trading)

Modesto Irrigation District

The Montana Power Company

Morgan Stanley Capital Group Inc.

Non-Public Utility Municipal Systems

Northern California Power Agency

Public Service Company of New Mexico

Public Systems (Public Utility District No.1 of Chelan County, Washington; Sacramento Municipal Utility District; Public Utility District No. 2 of Grant County, Washington; Public Utility District No.1 of Franklin County, Washington; Public Utility District No.1 of Grays Harbor County, Washington; and Northern California Power Agency)

Sacramento Municipal Utility District

Salt River Project Agricultural Improvement and Power District

Springfield Utility Board

Transaction Finality Group (TFG)

Truckee Donner Public Utility District

Washington State Attorney General (Washington AG)

Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission (Joint Comments)

William L. MASSEY, Commissioner, *dissenting*:

I strongly disagree with today's order. I would set a refund effective date of December 25, 2000 and order refunds for spot market transactions (defined as one month or less) through June 20, 2001.

Puget filed a complaint on October 26, 2000 requesting the Commission to cap prices for sales into Pacific Northwest wholesale power markets. The Commission could set a refund effective date of December 25, 2000. Thus, refund protection could be available for much of the time that prices throughout the West, including the Northwest, were at their highest due to the Western power crisis. Today's order notes that this Commission has recognized the integrated nature of the Western markets and notes that the ALJ in this case determined that the dysfunctions in the California spot markets affected prices in the Pacific Northwest. I would note that the Commission found as early as November 2000 that conditions in California caused and continued to have the potential to cause unjust and unreasonable rates and that market power could be exercised.[1] Unjust and unreasonable California spot prices during the relevant period drove Pacific Northwest prices to unlawful levels as well, and the staff's Western Markets Report details evidence of epidemic market manipulation that influenced prices throughout the West.

Yet today's order finds that refunds would be "inequitable" and refuses to order any refunds to customers in the Northwest, a region that suffered some of the heaviest economic consequences of the Western market meltdown. I strongly disagree with this con-

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[1] 93 FERC ¶ 61,121, at p. 61,349 (2000).

clusion. This market crisis had a significant impact upon the economy of the Pacific Northwest. Consumers were harmed, thousands of jobs were lost, and businesses closed. The aluminum industry virtually exited the Pacific Northwest.

The order sets out a number of unpersuasive reasons for not requiring refunds. First, the order is concerned that the burden of paying refunds will fall on a limited class of jurisdictional sellers in the region. This is because a large portion of the power in the Northwest is bought and sold by government entities whose sales are not jurisdictional to the Commission, and such entities are embedded in the chain of power purchases and resales that occurred in the region. Nonetheless, the majority order perpetuates an inequity that is much worse by comparison, namely, customers paying unjust and unreasonable rates that are unlawful under the Federal Power Act. The Commission has always taken its limited jurisdiction as it found it and made the best of it. We must do so here. We would never, for example, refuse to remedy the undue discrimination by jurisdictional utilities by arguing that we have no power to remedy the same conduct of non-jurisdictional entities. I do not believe that Section 206 of the Federal Power Act gives us the luxury of discretion when it comes to remedying unlawful rates. The fact that we cannot do complete justice is not an excuse for doing no justice.

Another rationale given in today's order is that refunds would unfairly reward entities that relied on the spot market. Even if the Commission has the discretion not to remedy unjust and unreasonable rates, which I do not concede, this is a curious rationale given the majority's decision in the long term

contract cases decided today. In those orders, the majority also refuses to provide any relief to those purchasing utilities, including some in the Northwest, that followed the Commission's admonition in the December 2000 order to move load out of the spot market, and signed forward contracts in an out of control market. The instant order and the concurrent long term contract orders breathe life into the old saying "damned if you do and damned if you don't."

The order also holds that refunds would have adverse consequences on the market in that ordering them would rewrite the rules that participants relied upon, would undermine the credibility of the regulatory process, and jeopardize investment. How one characterizes the consequences of a refund decision probably depends on which side of the market one sits. I would strongly argue that not providing refund relief would have many of the same consequences. The Commission wisely rejected these same arguments in ordering nine months of refunds to compensate for unjust and unreasonable spot prices in the California markets. Market participants in the Pacific Northwest will quickly lose faith in competitive markets if the Commission fails to protect them from unjust and unreasonable prices arising from a dysfunctional market that allowed the opportunity to exercise market power, and where market prices were driven in part by serious market manipulation.

And finally, the order is concerned with the time and effort that might result from the potential ripple claims as a result of a refund order here and the need to unravel perhaps as many as 500,000 transactions. Boiled down to its essence, the Commission is con-

fessing that it is just too hard to remedy the economic injustices that resulted from unjust and unreasonable rates that were charged in jurisdictional markets. Again, I do not believe the Federal Power Act gives us the luxury of discretion.

In fixing just and reasonable prices, and measuring refund liability, I would use the mitigated market clearing price (MMCP) methodology established in the California spot markets and set out in a series of Commission orders, most recently in an order of March 26, 2003.[2] This methodology would have to be modified to fit daily and up to monthly transactions, but it would provide a rational benchmark for determining refund liability in the Pacific Northwest.

For these reasons, I dissent from today's order.

Nora Mead BROWNELL, Commissioner, *concurring:*

1. I support the conclusion and reasoning of this order. An additional basis for my decision is the fact that this case involves bilateral transactions, the bulk of which were entered into under the WSPP Agreement. The Commission is concluding in another order being issued concurrently that modifications to contracts under the WSPP Agreement are subject to the *Mobile-Sierra* public interest standard of review.[1] I agree with the ALJ's finding that the refund claimants have not met that standard here.[2]

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[2] *San Diego Gas & Electric Company*, 102 FERC ¶ 61,317 (2003).

[1] *PacifiCorp v. Reliant Energy Services, Inc., et al.*, 103 FERC ¶ 61,355 (2003).

[2] *Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy, et al.*, 96 FERC ¶ 63,044, at p. 65,384 (2001).

FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Docket No. EL01-10-011

Order Denying Rehearing

(Issued November 10, 2003)

Before Commissioners: Pat Wood, III, Chairman; William L. Massey, and Nora Mead Brownell.

1. In this order, we deny requests for rehearing of our June 25, 2003 Order[1] (June 25 Order) in which we terminated the Pacific Northwest refund proceeding, which was an outgrowth of a complaint for a regional price cap filed by Puget Sound Energy, Inc. (Puget).

Background

A. *Procedural History*

2. On October 26, 2000, Puget filed a complaint petitioning the Commission for an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy or capacity under the Western Systems Power Pool (WSPP) Agreement, may sell energy or capacity into the Pacific Northwest's wholesale power markets.

3. The Commission dismissed Puget's complaint in a December 15, 2000 Order.[2] Subsequently, in con-

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[1] *Puget Sound Energy, Inc. v. All Jurisdictional Sellers, et al.*, 103 FERC ¶ 61,348 (2003).

[2] *San Diego Gas & Electric Company, et al.*, 93 FERC ¶ 61,294 (2000).

sideration of certain parties that were seeking settlement of claims related to sales in the Pacific Northwest, the Commission set the matter for a preliminary evidentiary hearing before an Administrative Law Judge (ALJ) to "explore whether there may have been unjust and unreasonable charges for spot market sales" in the region and the calculation of any refunds associated with such charges.[3] The Commission, however, did not establish a refund effective date.

4. On September 24, 2001, the Presiding ALJ in the preliminary evidentiary proceeding issued her recommendations and proposed findings of fact.[4] The ALJ recommended to the Commission that no refunds are warranted for wholesale power sales made in the Pacific Northwest between December 25, 2000 and June 20, 2001. In essence, she concluded that the evidence demonstrated that the Pacific Northwest market for spot sales of electricity was competitive and functional during the relevant period of time, and prices were just and reasonable.[5]

5. On June 2, 2003, the Commission heard oral argument regarding refunds.[6]

B. *The June 25 Order*

6. In the June 25 Order, the Commission first denied a pending motion by Puget to withdraw its

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[3] *San Diego Gas & Electric Company, et al.*, 96 FERC ¶ 61,120, at pp. 61,499-500 (2001) (July 2001 Order).

[4] *Puget Sound Energy, Inc., et al.*, 96 FERC ¶ 63,044 (2001) (ALJ Recommendations).

[5] Additional details regarding the procedural history of the case are provided in the June 25 Order at P 4-20.

[6] *See* Notice Scheduling Oral Argument, 68 *Fed. Reg.* 32,031 (2003).

pleadings. The order further granted Puget's request for rehearing of the Commission's December 2000 decision to dismiss the complaint. The order then noted that the relief requested by Puget was provided by a June 19, 2001 Order (June 2001 Order) in which the Commission implemented price mitigation measures on wholesale sales throughout the West.[7]

7. Next, the Commission concluded that, while it technically may have authority to require refunds for a short prior period, "based on the record before us . . . even if prices were unjust and unreasonable, it is not possible to fashion a remedy that would be equitable to all the participants in the Pacific Northwest market."[8] The order then elaborated on circumstances unique to the proceeding that prevent an even and fair allocation of refunds (if determined to be warranted). First, the burden of paying refunds would fall on a limited class of jurisdictional sellers in the region since a large portion of transactions at issue are were conducted by governmental entities and, therefore, not subject to the Commission's refund authority pursuant to Section 206 of the Federal Power Act (FPA), 16 U.S.C. § 824e (2000).

8. Further, the June 25 Order explained that refunds would unfairly reward entities that relied on the spot market, while other market participants that paid for hedge instruments or engaged in procurement strategies that included a higher balance of long-term instruments would not receive refunds.

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[7] *San Diego Gas & Electric Company, et al.*, 95 FERC ¶ 61,418 (2001), *order on reh'g*, 97 FERC ¶ 61,275 (2001), *order on reh'g*, 99 FERC ¶ 61,160 (2002), *appeal sub nom. Public Utilities Comm. of the State of California, et al. v. FERC*, Nos. 01-71051 *et al.* (9th Cir. June 29, 2001 and later).

[8] June 25 Order at P 35.

The order adopted the ALJ's findings that the fair and accurate calculation of refunds may not be possible due to the sheer volume of transactions that would be implicated in a refund proceeding (estimated at approximately 500,000 transactions during the relevant time frame) and other complications such as the inability to trace upstream sellers in all transactions. The Commission also expressed concern that refunds would have adverse consequences to the Pacific Northwest spot market, a concern also expressed by the Washington Utilities and Transportation, Oregon Office of Energy and the Oregon Public Utility Commission (State Commissions) in their pleadings in the case. Thus, based on the totality of circumstances, the Commission terminated the matter without further proceedings because, even if prices were unjust and unreasonable, the directing of refunds would not result in an equitable resolution of the proceeding.

C. *Requests for Rehearing*

9. Timely requests for rehearing were filed by the City of Seattle, Washington (City of Seattle), the City of Tacoma, Washington (Tacoma), California State Parties,[9] Port of Seattle (Port), Public Utility District No. 1 of Grays Harbor, Washington (Grays Harbor) and the Transaction Finality Group.[10]

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[9] California State Parties consists of the People of the State of California *ex rel.* Bill Lockyer, Attorney General, the California Electricity Oversight Board and the California Public Utilities Commission.

[10] The Transaction Finality Group or "TFG" consists of Puget, TransCanada Energy Ltd., Duke Energy Trading & Marketing LLC, Avista Corp., Avista Energy, Inc., Portland General Electric Company, IDACORP Energy L.P., Coral Power, L.L.C., PPL Montana, LLC, PPL EnergyPlus, LLC, Pinnacle West Capital

Discussion

A. *Requests Denied on Procedural Grounds*

10. Parties raise on rehearing several issues that were not addressed in the June 25 Order. Grays Harbor argues that its six-month contract at issue falls within the definition of "spot market transactions in the Pacific Northwest." Likewise, City of Seattle claims that the Commission erred by not addressing the appropriate definition of "spot market." Port of Seattle argues that the ALJ erred in placing the burden of proof on refund claimants to show that rates were unjust and unreasonable.

11. The ALJ recommended that the definition of "spot market" for the region be limited to transactions of less than one month duration. However, the June 25 Order did not adopt or reject this specific ALJ recommendation as it was not relevant to the Commission's decision to terminate the proceeding, and need not be addressed. Likewise, the Commission did not either adopt or reject the ALJ's conclusion that spot market rates in the region were just and reasonable, as the decision to terminate the proceeding was based on other considerations. Accordingly, Port's argument that it wrongly had to bear the burden of proof to show that rates were unjust

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Corporation, Arizona Public Service Corp., Sempra Energy Trading Corp., Tractebel Energy Marketing Inc., TransAlta Energy Marketing (CA) Inc., TransAlta Energy Marketing (US) Inc., Public Service Company of Colorado, Alcoa Inc., Columbia Falls Aluminum Company, LLC, BP Energy Company, PG&E Trading-Power, L.P., El Paso Merchant Energy, L.P., Public Utility District No. 2 of Grant County, Washington, City of Los Angeles Department of Water and Power, Morgan Stanley Capital Group Inc., Public Service Company of New Mexico, Powerex Corp., Public Utility District No. 1 of Benton County, Washington, and Constellation Power Source, Inc.

and unreasonable is not relevant to our decision and need not be addressed.

B. *Denial of Puget's Motion to Withdraw its Pleadings*

12. The June 25 Order denied Puget's motion to withdraw its complaint and other pleadings. The Commission rejected Puget's argument that its petition to withdraw was granted by operation of law since no "party" objected and the Commission failed to act within 15 days.[11] The Commission explained that several non-parties filed timely objections, and Rule 216 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.216 (2003), does not state that the motion opposing a notice of withdrawal must be filed by a party.[12] Further, the non-parties were granted late intervention, making them parties to the proceeding.

13. TFG, which is opposed to refunds, argues that the Commission erred by failing to recognize that Puget's motion to withdraw its complaint was granted as a matter of law on July 9, 2001, 15 days after it filed the motion. TFG claims that, while Rule 216 does not explicitly state that a motion in opposition to a notice of withdrawal must be filed by a party, Rule 212(a)(2) makes clear that motions can only be made by a "person" or a "participant" who has filed a timely motion to intervene which has not been denied. (Rule 102 defines "parties" to include any person "whose intervention is effective.") TFG con-

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[11] June 25 Order at P 25 n 19.

[12] Rule 216, which sets forth the rules for the withdrawal of pleadings, provides that a withdrawal is effective 15 days after a notice of withdrawal is filed, provided that no motion in opposition to the notice of withdrawal is filed within the period and provided that the decisional authority does not issue an order disallowing the withdrawal within that period.

tends that the Commission erred in relying on the opposition of non-parties in denying Puget's request to withdrawal it pleadings. According to TFG, the subsequent grants of intervention of the opposing parties did not cure their non-party status since the grant of late intervention does not work retroactively. Rather, late interveners must accept the record of the proceeding as the record was developed prior to the late intervention. Rule 214(d).

Commission Determination

14. Puget's motion to withdraw its pleadings was timely opposed by several entities that, in the same filing, moved for late intervention in the proceeding.[13] According to TFG's position, the Commission could have properly considered the opposition motions had the Commission granted the motions for late intervention on the day they were filed because, in that case, a party to the proceeding would have timely opposed the motion to withdraw. However, the Commission must provide others the opportunity to protest or comment on the motions for late intervention. The Commission subsequently granted the motions for late intervention, giving the interveners party status in the proceeding. In these circumstances, it does not make sense that the oppositions cannot be considered simply because the Commission followed its procedures and did not grant late intervention immediately. Accordingly, the Commission denies TFG's request for rehearing on this issue.

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[13] On July 9, 2001, both the City of Seattle and The Attorney General of the State of Washington filed late motions to intervene and oppositions to Puget's motion to withdraw. The City of Tacoma and Port of Seattle also filed a timely "answer" to Puget's motion, but did not seek intervention until later.

C. *Due Process Issues*

1. *Nature and Scope of the Proceeding*

15. Port of Seattle and City of Tacoma contend that they were denied due process because the July 2001 Order was unreasonably vague as to the nature and scope of the preliminary evidentiary hearing, which was referred to as "preliminary" (implying a second proceeding) and "evidentiary," but in certain places indicated that the proceeding was simply a "discussion." This led to confusion regarding the issues to be litigated and the conclusive effect of the proceedings. Further, they claim that the accelerated procedural schedule prevented participants from effectively presenting their case. According to Tacoma and the Port, participants were given an inadequate opportunity to conduct discovery, could not take depositions of fact witnesses, had only three days after the filing of initial testimony to file rebuttal testimony with direct testimony arriving in some cases the same day that rebuttal was due, and were forced to waive cross-examination of many witnesses in order to have sufficient time to devote to other witnesses.

16. They claim that the re-opening of the record in the "100-day discovery" proceeding did not cure the defects because the Commission failed to provide a second opportunity for a trial-type hearing, and was anyway ignored in the Commission's June 25 Order. They argue that, as a result, the Commission erred in relying on the ALJ's proposed findings as a result of these defects.

Commission Determination

17. The Commission provided sufficient due process in this proceeding. The reason for this conclusion

is best understood from the context in which the preliminary evidentiary hearing arose. When Puget filed its complaint, notice was published in the *Federal Register*. Respondents and other interested parties had a full opportunity to file answers and comments. Based on the record established by this process, the Commission dismissed the Complaint.

18. Subsequently, while rehearing was pending but the complaint was still dismissed, the Commission decided, in consideration of certain parties that were seeking settlement of claims related to sales in the Pacific Northwest, to set the matter for a preliminary evidentiary hearing before an ALJ to "explore whether there may have been unjust and unreasonable charges for spot market sales" in the region. The July 2001 Order made clear that the complaint remained dismissed, but the Commission was providing additional as well as unusual process to determine whether the proceeding should continue or be terminated. (Given the posture of the case, the Commission declined to set a refund effective date when setting the matter for preliminary evidentiary hearing.) The July 2001 Order was sufficiently clear as demonstrated by the fact that the Presiding ALJ commenced an inquiry that comported with our instructions, and participants in the proceeding litigated the issues that would provide the Commission with relevant information to make a decision whether to continue or terminate the proceeding.

19. Despite the accelerated schedule, the participants engaged in discovery, prepared testimony of over 40 witnesses, followed by rebuttal testimony and cross-examination and filed post-hearing briefs. After the ALJ issued her proposed findings of fact and recommendations, parties had the opportunity to

file comments with the Commission. The Commission allowed participants in the proceeding to further supplement the record in March 2003.[14]

20. The Commission provided adequate due process when it provided an opportunity for respondents and other interested entities to respond to Puget's complaint. Based on the record, the Commission determined that the complaint should be dismissed. This decision was challenged on rehearing by no-one but Puget. This opportunity to submit fact and argument satisfies due process as well as the Administrative Procedure Act.[15] The Commission, however, in the interest of fairness, provided two additional opportunities for participants in the proceeding to make a case for refunds.

21. Having already satisfied the due process requirements, the accelerated nature of the ALJ proceeding did not violate participants' due process rights.[16] Moreover, standing alone, the ALJ proceeding provided adequate due process. As mentioned above, participants engaged in discovery, prepared

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[14] *See Puget Sound Energy, Inc., et al.*, 101 FERC ¶ 61,304 (2002).

[15] *See* 5 U.S.C. § 554(c) (2000) (the agency shall give all interested parties opportunity for the submission and consideration of facts); *Vermont Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 543-44 (1978); *Exxon Co., U.S.A. v. FERC*, 182 F.3d 30, 45-47 (D.C. Cir. 1999) (Commission may resolve factual issues on a written record unless motive, intent, or credibility are at issue or there is a dispute over past events).

[16] *Louisiana Association of Independent Producers & Royalty Owners v. FERC*, 958 FERC 1101, 1113-1114 (D.C. Cir. 1992) (finding limited hearing procedures to be acceptable because "once due process is satisfied the amount and form of any additional process an agency wishes to provide is left almost entirely to its discretion").

testimony of over 40 witnesses, followed by rebuttal testimony and cross-examination, filed post-hearing briefs with the ALJ, and after the ALJ issuance, parties had the opportunity to file comments with the Commission. The constraints of the rigorous schedule identified by the Port and Tacoma do not amount to a denial of due process.

22. Further, the Commission's reliance on the written pleadings in the reopening of the record in this proceeding provides sufficient due process, as the Commission is not required to hold a trial-type evidentiary hearing in every case.[17] In reaching its decision to terminate the proceeding, the Commission considered the complete record, including the material submitted in the March 2003 filings. Accordingly, Tacoma's and Port's due process rights were not violated but, to the contrary, the Commission provided additional opportunities to revive the complaint proceeding beyond that required by minimum due process requirements.

2. *No Parties' Rights Were Compromised by Establishment of the Preliminary Evidentiary Proceeding*

23. Port of Seattle argues that the July 2001 Order established a new and separate proceeding involving parties from both the Puget (EL01-10) and San Diego (EL00-95) complaint proceedings and encompassing substantive rights from both dockets. According to the Port, the proceeding, as implemented, has been treated as a continuation of the Puget complaint alone, thereby wrongfully extinguishing any rights or claims that emanated from the San Diego proceeding (also known as the "California refund proceeding").

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[17] *E.g., Southern California Edison Co.*, 70 FERC ¶ 61,087, at p. 61,251 & n.43 (1995).

However, the Port misreads the July 2001 Order. In that Order, the Commission clearly established the preliminary evidentiary hearing to address issues in Docket No. EL01-10-000, the Puget Sound complaint, the only relevant complaint proceeding that relates to the Pacific Northwest.[18] Further, Port's argument makes no sense since the San Diego docket was limited to mitigation of the centralized California Independent System Operator (ISO) and California Power Exchange (PX) markets in California, and did not include bilateral purchases made outside of California.[19] Thus, no rights or claims emanating from the California refund proceeding could have been compromised by creation of a separate proceeding in Docket No. EL01-10 to explore possible refunds in the Pacific Northwest.

D. *The Commission Engaged in an Appropriate Exercise of its Discretion in Terminating the Proceeding Without Deciding Whether Rates in the Pacific Northwest Were Unjust and Unreasonable*

24. While the June 25 Order found that electricity prices "rose dramatically," it did not make a finding whether prices were unjust and unreasonable. Nor did the Commission make a finding regarding the cause(s) of the high prices. Rather, it determined that the West-wide price mitigation plan adopted by the Commission in the June 2001 Order "provided the relief requested by Puget, and on a forward basis the relief sought by other participants in the com-

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[18] July 2001 Order, 96 FERC ¶ 61,120, at pp. 61,500, 61,502-03 and 61,520-21.

[19] *Id.*, at p. 61,515 (clarifying that DWR bilateral contracts were not subject to refund because "imposing after-the-fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified").

plaint proceeding."[20] Further, the Commission concluded that, based on the record established in the preliminary evidentiary hearing, "even if prices were unjust and unreasonable, it is not possible to fashion a remedy that would be equitable to all the participants in the Pacific Northwest market."[21] The Commission noted that its broad discretion in fashioning remedies includes the authority to determine that it would be inappropriate, in a particular case, to provide a remedy.[22]

25. City of Tacoma, City of Seattle, California State Parties and Port of Seattle argue that the Commission erred by failing to find that prices in the Pacific Northwest were unjust and unreasonable. They contend that the Commission is compelled to make this finding based on record evidence, and that the Commission is bound by prior decisions in which it already made such a finding. Grays Harbor claims that the June 25 Order in fact acknowledged that prices were unjust and unreasonable during the spring of 2001.

26. Building on the premise that rates were unjust and unreasonable, parties argue that the Commission has no discretion when rates are found to be unjust and unreasonable and must provide refunds. City of Seattle states that the Commission may not refuse to order refunds where the denial of relief would violate the core purpose of the FPA.[23] It argues that the denial of refunds in this proceeding violates

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[20] June 25 Order at P 33.

[21] *Id.*, at P 35. *See also id.* at P 53.

[22] *Id.*, at P 52 & n.64.

[23] *Citing Maislin Industries, U.S., Inc. v. Primary Steel, Inc.*, 497 U.S. 116 (1990).

the FPA's core purpose of protecting purchasers in the Pacific Northwest from unjust and unreasonable rates as mandated by Sections 205 and 206 of the FPA. It also argues that refunds are non-discretionary in this case because the Commission cannot authorize sellers to charge market-based rates unless it finds that the market is functionally competitive, yet the Commission has repeatedly found that the Western markets including the Pacific Northwest were dysfunctional and pervaded by market abuse. Further, it contends that the Commission's decision to allow sellers to retain the unjust profits they realized renders nugatory the provisions of Section 206 that prevent sellers from retaining the revenues in excess of just and reasonable prices collected during a pending Section 206 investigation. Related, City of Seattle also argues that the Commission departed, without explanation, from precedent establishing a Commission policy of granting full refund of all amounts charged in excess of the just and reasonable price.

27. The Port argues that, under FPA Section 206, if the Commission finds that existing charges are unjust and unreasonable, it is required (without discretion) to determine the just and reasonable rate. It also contends that the filing of a complaint imposes a statutory obligation on the Commission to determine whether prices are unjust and unreasonable. Yet, while the Commission has made such a determination in the California refund proceeding, it has failed to do so in the Pacific Northwest proceeding. It argues that, "[g]iven the Commission's determination that prices in excess of the [market clearing price] are unlawful *per se* there is no rational basis upon which to refund revenues collected in excess of the

[market clearing price] in California while refusing to do so in the Pacific Northwest."[24]

28. In a similar vein, Tacoma and City of Seattle argue that that the denial of refunds is unlawfully discriminatory. They contend that the Commission cannot treat a market participant's purchases in the Pacific Northwest any different from its purchases in the California ISO and PX spot markets unless there is a rational basis for such treatment. According to City of Seattle, the dysfunctional California spot markets caused the unjust and unreasonable prices in the interconnected spot market in the Pacific Northwest. Therefore, purchasers in the in the Pacific Northwest spot market paid the exact same exorbitant prices as purchaser in the ISO and PX spot markets. Yet, the Commission has ordered sellers in the California spot markets to pay refunds while denying the same relief to purchasers in the Pacific Northwest, a selective refund remedy that treats similarly-situated persons differently is unlawful.[25] City of Seattle also contends that the June 25 Order unduly discriminates against purchasers in the Pacific Northwest by allowing a disgorgement remedy in the California markets but failing to even discuss City of Seattle's request for disgorgement of excess profits realized by sellers in the Pacific Northwest.

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[24] Port request for rehearing at 27.

[25] Citing July 2001 Order at 61,514.

Commission Determination

1. *The Commission Is Not Required To Make a Determination Whether Rates Were Unjust and Unreasonable*

29. The Commission is not required to make a determination whether prices were unjust and unreasonable in the Pacific Northwest spot markets for the potential refund period in this proceeding.[26] Indeed, the Commission never determined whether the just and reasonable standard would have been the correct standard to apply.[27] A substantial majority of the bilateral contracts at issue were transacted pursuant to the WSPP Agreement. In recent decisions, the Commission has determined that, pursuant to the *Mobile-Sierra* doctrine, the public interest standard is the applicable standard of review for transactions that took place pursuant to the WSPP Agreement.[28] Thus, it is quite possible that the public

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[26] The refund period is only "potential" because the Commission never established a refund effective date in the proceeding. The June 25 Order determined that the Commission technically had the authority to set a refund effective date, but found it unnecessary to do so because of the decision to terminate the proceeding.

[27] While the July 2001 Order directed the ALJ to explore whether there may have been unjust and unreasonable charges for spot market sales, this cannot be understood as a Commission determination regarding the applicable standard, as the issue had not yet been raised. The issue of which standard applies to the contracts involved in this proceeding was raised for the first time in pleadings before the ALJ. The ALJ, in her recommendations, identified the applicability of the *Mobile-Sierra* doctrine as an issue that the Commission would have to decide if further proceedings were ordered in this case. *See* ALJ Recommendations, 96 FERC ¶ 63,044, at p. 65,384.

[28] *E.g.*, *Nevada Power Co., et al.*, 103 FERC ¶ 61,353 (2003), *pending reh'g.*

interest standard would have applied in the current proceeding as well, if we had found it necessary to reach the issue.

30. As noted above, the Commission initially dismissed Puget's complaint in a December 2000 Order. Certainly, the Commission had no reason to make a rate-related finding in the proceeding prior to issuance of the July 2001 Order in which the Commission reconsidered its earlier decision and set the matter for a preliminary evidentiary hearing before an ALJ. In the July 2001 Order, the Commission tasked an ALJ to develop "a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales" in the region.[29] This directive cannot be construed as a determination on the matter but, rather, confirms that the Commission desired additional information before making a decision.

31. The Commission orders relied upon by the parties seeking rehearing relate either to the California "real time" markets[30] or to the entire West-wide market for a time other than the potential refund period at issue in this proceeding.[31]

2. *The Commission Engaged in an Appropriate Exercise of its Discretion in Terminating the Proceeding*

32. Parties seeking refunds argue that the Commission lacks discretion in this matter and must direct refunds based on the language of FPA Section 206 and because the denial of refunds would violate the core purpose of the FPA. We reject these argu-

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[29] July 2001 Order, 96 FERC ¶ 61,120, at p. 61,520.

[30] *E.g.*, July 2001 Order.

[31] *E.g.*, June 2001 Order.

ments. First, these arguments are premised on the notion that rates were unjust and unreasonable, a finding that the Commission has not made. Further, under FPA Section 206(b), refunds in fact are discretionary, as the statute provides that "at the conclusion of any proceeding under this section, the Commission *may* order the public utility to make refunds . . . ."[32]

33. Moreover, Puget, in its complaint, requested a regional price cap as a remedy, not refunds.[33] The June 25 Order determined that the appropriate remedy was provided by the implementation of the West-wide price mitigation plan in June 2001, and Puget has indicated that this remedy is satisfactory. The parties seeking refunds are interveners in this matter, and have not filed a separate complaint. As interveners, these parties are not in the position to argue that the Commission must determine a just and reasonable rate under FPA Section 206(a) or that the Commission's remedy offends a core purpose of the statute. Rather, the Commission, in a reasonable exercise of its discretion, provided a remedy of a prospective price cap – the precise remedy requested by the complainant.

34. Further, the Commission determined that, due to the unique circumstances present in the Pacific Northwest, it is not possible to fashion a refund

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[32] 16 U.S.C. § 824e(b) (2000) (emphasis added).

[33] *See* Puget Complaint at Introduction and Paragraphs 14-16. In a section of the Complaint titled "other matters," Puget makes clear that it seeks prospective relief only, and then asks that a refund effective date be set pursuant to FPA Section 206(b). It is clear from the context that Puget sought a price cap, and requested a refund effective date to fulfill the statutory requirement.

remedy that would be fair and equitable to all market participants in the region. Having made such a determination, it was unnecessary to proceed further. Based on these circumstances, the Commission engaged in a proper exercise of its discretion in terminating the proceeding without directing refunds.

35. The termination of the proceeding was not unduly discriminatory since the interveners seeking rehearing in this proceeding are not similarly situated to market participants in the California spot markets. Major differences include the fact that the California ISO and PX markets are centralized with a single clearing price for the spot markets,[34] while the Pacific Northwest spot markets are based on bilateral contracts between individual market participants. The major utilities in California were prevented by law from entering into forward contracts during the relevant period of time, while the Pacific Northwest market participants were free to enter into forward contracts. Further, as discussed in the next section, while the Commission has jurisdiction over the transactions of governmental entities that participated in the California spot markets, the Commission does not have jurisdiction over the transactions of governmental entities that participated in the Pacific Northwest spot markets. The Commission has in various contexts recognized the integrated nature of the Western markets. However, that fact alone does not dictate refunds. The significant differences between the California and Pacific Northwest spot markets, as well as the differing procedural postures of the California refund and Pacific Northwest proceedings, refute the notion that the different

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[34] *See* July 2001 Order, 96 FERC ¶ 61,120, at pp. 61,511-513.

outcomes in the two proceedings results in unlawful discrimination to market participants in the Pacific Northwest.

36. City of Seattle argues that, by denying refunds in the Pacific Northwest, the Commission has departed without explanation from a policy of granting refunds of all amounts in excess of the just and reasonable price. Aside from the fact that the Commission has not determined that prices were unjust and unreasonable, City of Seattle's argument is best refuted by the same statement on which it relies to make its argument, "the Commission's practice has been to order full refunds of any amounts collected above the just and reasonable level, *absent contrary equitable considerations*."[35] The June 25 Order found that refunds were not appropriate due to the presence of overriding equitable considerations.[36]

E. *The Equitable Considerations Relied Upon by the Commission Justify Termination of this Proceeding*

1. *The Inability to Impose Refund Liability on the Transactions of Governmental Entities*

37. The June 25 Order concluded that the Commission does not have authority to impose refund

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[35] City of Seattle, request for rehearing at 28, *quoting San Diego Gas & Electric Co., et al.*, 97 FERC ¶ 61,275, at p. 62,185 (2001) (emphasis added).

[36] City of Seattle, rehearing at 34, argues that the Commission failed to consider relevant equitable factors such as the impact of the denial of refunds on load serving entities. Again, the thrust of the June 25 Order was that no equitable remedy is available and that granting the requested refund remedy would simply serve to redistribute the inequities, but would not make the market whole. In balance, the Commission believes that this fundamental, overriding equitable consideration should prevail.

liability on the transactions of governmental entities that participated in the bilateral spot market for electricity in the Pacific Northwest.[37] The Commission explained that governmental entities account for a large portion of the power bought and sold in the region. Since electricity in the region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain, and governmental entities will likely often be included in the chain, the burden of paying refunds would "fall on a limited class of jurisdictional sellers in the region; and the benefit of receiving refunds will be available only to buyers who bought from those same sellers."[38] The Commission found that allowing refunds in such circumstances would be "inequitable and unbalanced."

38. On rehearing, California State Parties argue that the Commission erred in finding that it lacks authority to require governmental entities in the Pacific Northwest to pay refunds in this proceeding. They claim that the same rationale that applies to the Commission's assertion of jurisdiction over transactions of governmental entities in the California refund proceeding applies in the Pacific Northwest as well. They argue that the same conditioning authority relied upon by the Commission in the June 19, 2001 Order to establish a mitigated price applicable prospectively to wholesale power transactions in the Pacific Northwest involving governmental entities could be invoked to establish a mitigated benchmark price prospectively from a refund effective date.

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[37] June 25 Order at P 36 38. *See also* FPA Section 201(f), 16 U.S.C. § 824(f) (2000).

[38] *Id.*, at P 39, *quoting ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,370.

39. City of Seattle, Tacoma, Port of Seattle, and California State Parties argue that, even if the Commission lacks refund authority over the transactions of governmental entities, this is no reason to avoid directing jurisdictional sellers in the region to make refunds for sales at unjust and unreasonable prices. They contend that, even if complete justice cannot be done, the Commission should do what is in its power to remedy unjust and unreasonable rates. California State Parties argue that the Commission's lack of refund authority over governmental entities is, in any case, irrelevant to their particular circumstances since 85% of the refund amount that they seek is from Commission-jurisdictional entities. Likewise, Grays Harbor states that it seeks refunds for a single transaction with a Commission-jurisdictional entity.

Commission Determination

40. The Commission correctly determined that it does not have FPA Section 206 refund authority over the transactions of governmental entity sellers in the Pacific Northwest. For the reasons stated in the June 25 Order,[39] we are not convinced by California State Parties' attempt to liken bilateral transactions made pursuant to the Commission-approved WSPP Agreement to the transactions in the California centralized markets. In addition, we note that, in the California markets, governmental entity sellers entered into arrangements that acknowledged the Commission's authority over the centralized transac-

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[39] June 25 Order at P 36-38. *See also ALJ's Recommendations*, 96 FERC ¶ 63,044, at p. 65,370; *cf.*, July 2001 Order, 96 FERC ¶ 61,120, at pp. 61,511-513.

tion.[40] In contrast, the WSPP Agreement specifically states that nothing in the Agreement provides the Commission with jurisdiction over parties that are not otherwise subject to Commission jurisdiction, including state or federal agencies.[41]

41. California State Parties also rely on the Commission's application of the West-wide mitigation plan to governmental entities throughout the West. However, that aspect of the plan was subsequently reversed.[42] Further, we reject their argument that the Commission could invoke its conditioning authority to prospectively mitigate, from a refund effective date, the sales transactions of governmental entities in the Pacific Northwest. The problem with this argument is that, rather than establishing a refund effective date, the Commission dismissed Puget's complaint in December 2000. Throughout the potential refund period, market participants had every reason to believe that the complaint was terminated. The Commission did not indicate until July 2001, after the end-date of the potential refund period, that it would reconsider the possibility of refunds. Thus, California State Parties are wrong to suggest that this proceeding is ripe for "prospective" conditioning

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[40] July 2001 Order, 96 FERC ¶ 61,120, at p. 61,513.

[41] *See* WSPP Agreement Section 13.1. (Submitted as Exhibit No. NPG-24.) In *Western Systems Power Pool*, 55 FERC ¶ 61,495, at p. 62,713 (1991), the Commission explained that it "cannot assert jurisdiction over nonpublic utility members of the WSPP" and that the decision of nonpublic utility members of the WSPP to be bound by contract to the Agreement is not a matter for the Commission under the FPA.

[42] *San Diego Gas & Electric Co., et al.*, 97 FERC ¶ 61,275, at p. 62,252 (2001).

of governmental entities' (or, for that matter, any other market participants') sales transactions.

42. As mentioned above, certain refund claimants argue on rehearing that, even if the Commission cannot direct refunds for the transactions of governmental entities, the Commission should do "partial justice" by directing jurisdictional sellers in the Pacific Northwest to make refunds for unjust and unreasonable rates. Assuming that the Commission found that rates were unjust and unreasonable (or, perhaps, not in the public interest), the ordering of refunds would not result in "partial justice" but, rather, an arbitrary redistribution of inequities. Whether or not a purchaser would receive a refund for a particular transaction would arbitrarily depend on whether the counter-party happened to be a jurisdictional entity. The fact that Grays Harbor and California State Parties on behalf of CERS can identify jurisdictional sellers as their counter-parties would not change the arbitrary nature of any attempt to remedy the Pacific Northwest spot market.[43]

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[43] The ALJ, in determining the proper definition of "Pacific Northwest" for purposes of the proceeding, recommended that the California State Parties claims for refunds of CERS bilateral transactions should not be considered in the proceeding. *ALJ Recommendations*, 96 FERC ¶ 63,044, at pp. 65,331-332 and Proposed Findings of Fact 1-2, 25-36. She explained that Puget's complaint referred specifically to a price cap on sales of capacity and energy "into" the Pacific Northwest. However, she concluded, the bilateral transactions involving CERS were sales into California, not into the Pacific Northwest. She found that southbound wholesale sales of power at the California-Oregon Border and Nevada-Oregon Border interconnections are not within the Pacific Northwest because the delivery point is not to a Pacific Northwest load server and because deliveries actually take place in California. *Id.* Therefore, she concluded that the CERS transactions were outside the scope of the proceeding.

43. Thus, the Commission found compelling the reasoning of the State Commissions:

> the burden of paying refunds will fall on a limited class of jurisdictional sellers in the region; and the benefit of receiving refunds will be available only to buyers who bought from those same sellers. Some entities, the public utilities, will be subject to pay refunds, but not entitled to receive refunds from non-public utilities that sold power at the very same elevated and volatile prices. This asymmetry would be an inequitable outcome serving not to remedy the market dysfunction, but rather, to send the bill for market dysfunction to sellers who comprise only a portion of the market-sales volume.[44]

44. Accordingly, requests for rehearing on this issue are denied.

2. *Refunds are Not an Appropriate Remedy*

45. The June 25 Order concluded that refunds would unfairly reward entities that relied on the spot market.[45] The Order explained that a full array of short, medium and long-term contracts, as well as hedging instruments were available to market

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We find that the ALJ's definition of "Pacific Northwest" and her conclusion that CERS transactions are outside the scope of this proceeding are reasonable and supported by the record and we, therefore, adopt her proposed findings and recommendations on these matters.

[44] State Commissions Joint Post-Hearing Brief at 7. The Commission did not err in giving "due respect" to the position of the State Commissions, as argued by California State Parties, City of Seattle and the Port. These State agencies are responsible for protecting many of the retail ratepayers in the Pacific Northwest, and their position is therefore particularly germane to this proceeding.

[45] June 25 Order at PP 42.

participants in the Pacific Northwest. Since the proceeding only concerns spot transactions, entities that procured a higher balance of long-term instruments would not be eligible to receive refunds for such long-term contracts, yet they might be obligated to pay refunds for power purchased in long-term markets that was later sold in short-term markets.

46. Tacoma and City of Seattle argue that this conclusion is not relevant because purchasers in the Pacific Northwest, regardless of whether they made their purchases in the spot or forward market or hedged, should not have to accept the risk of unjust and unreasonable prices. Similarly, California State Parties contend that any sale that is not just and reasonable is unlawful and the Commission has a duty to act regardless of a market participants' reliance on the spot market. Port of Seattle contends that the conclusion is premised on the notion that "those who operated on the assumption that the Commission's determination that the region's markets were not subject to the exercise of market power . . . . should not have done so."[46] The Port further contends that the decision rewards entities that exercised market power. City of Seattle argues that the Commission's reasoning is inconsistent with its decision to grant refunds to buyers that relied on the California spot markets and its issuance of show cause orders directing the numerous entities to show cause why certain alleged gaming behavior does not violate the ISO and PX tariffs. City of Seattle, California State Parties and Tacoma claim that the Commission's conclusion is "disingenuous" and not based on reasoned decision-making given that the

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[46] Port at 30-31.

Commission has denied every complaint filed by a purchaser seeking to reform forward contracts in the western markets.[47]

47. Tacoma argues that the Commission should not have relied on the ALJ's proposed findings that the Pacific Northwest was generally forewarned of power supply shortages and hedging opportunities were available in the region because these proposed findings were outside of the scope of the preliminary evidentiary hearing. It also contends that the Commission failed to consider conflicting evidence, and refers to witness testimony indicating that Tacoma had purchased power to cover the sale of the Centralia generating plant. Grays Harbor contends that it had not willingly relied on the spot market but rather was forced into the market after the majority owners sold the Centralia plant over Grays Harbor's objection. City of Seattle claims that there is no evidence that its purchasing practices were imprudent, noting that the ALJ found that it made 99 percent of its purchases in the forward market. California State Parties argue that the Commission's rationale does not apply to purchases made by CERS since it began its purchasing responsibilities at the height of the energy crisis in January 2001 without any portfolio, and did not have the opportunity at that time to purchase long-term power at reasonable rates.

Commission Determination

48. The Commission's consideration of the fact that refunds would unfairly reward entities that relied on

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[47] *Citing Nevada Power Co.*, 103 FERC ¶ 61,353; *Public Utilities Commission of California*, 103 FERC ¶ 61,354 (2003), *reh'g pending*; and *PacifiCorp*, 103 FERC ¶ 61,353 (2003), *reh'g pending*.

the spot market was one of the factors the Commission considered in determining whether refunds are an appropriate remedy in the particular circumstances of this proceeding.

49. The arguments raised on rehearing are not persuasive. The thrust of the Commission's findings in the June 25 Order was that refunds are not appropriate because such relief would arbitrarily remedy only a portion of the regional market.

50. Contrary to the position of Tacoma and City of Seattle, the availability of long-term contracts as well as hedge instruments is relevant. When potential supply shortages are looming,[48] it is incumbent upon market participants to avail themselves of the instruments available in the marketplace to protect their interests. Market participants have to pay for hedge instruments and long-term contracts in order to protect their interests. Those who chose to avoid the cost must bear the risk.

51. The factual distinctions raised by certain parties, suggesting that they did not overly-rely on the spot market or that they had no choice but to participate in the spot market, are not relevant to the Commission's reasoning that refunds would arbitrarily remedy only a portion of the regional market.[49]

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[48] *ALJ Recommendations*, 96 FERC ¶ 63,044, at pp. 65,366-67. *See also, e.g.*, Exh. BPA-1 at 19.

[49] Moreover, the factual distinctions raised do not comport with the record in the proceeding. City of Seattle claims that the ALJ found that it made 99 percent of its purchases in the forward market. The Exhibit cited by the ALJ, PWX-3, refers specifically to City of Seattle's spot sales of 24 hours or less. However, the ALJ defined the spot market in the region as including transactions up to one month in duration. Based on the ALJ's definition, City of Seattle's participation in the spot

3. *Allowing Refunds Would Have Adverse Consequences on the Market*

52. The June 25 Order adopted the ALJ's proposed finding and determined that allowing refunds would have adverse consequences on the market by creating instability and driving away potential sellers.[50]

53. California State Parties and Tacoma contend that this finding is speculative and the Commission failed to identify any record evidence to support the finding. City of Seattle and the Port argue that denying refunds will have an adverse impact on the market, since it sends a signal that the market is "lawless" and prudent purchasers will not participate. City of Seattle also argues that the denial of refunds in a market in which unjust and unjust rates prevailed would re-write the rules on which

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market would be much greater; and if we were to apply the definition advocated by City of Seattle, which would include transactions up to 18 months duration, its participation in the spot market would increase greater still. On the other hand, TFG's proposed definition of 24 hours or less would, in fact, result in City of Seattle having spot market sales of less than 1 percent, and its refund claim significantly reduced. *See* Exhibits PWX-12 at pp 5-6 and PWX-13 (94% of refund claims are eliminated if limited to transactions of 24 hours of less). Further, the record indicates that Tacoma sold its 80 MW share of Centralia production. According to Tacoma, it covered this loss with a series of multi-month contracts. *See* Exh. NPG-57 at 3. However, it appears that these contracts – involving purchases from Powerex and BPA, from whom it now seeks refunds – in fact left Tacoma vulnerable to the fluctuations of the short term market. *See ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,343 and exhibits cited therein (discussing City of Seattle's and Tacoma's choosing to take the risk of high spot market prices). It can hardly be said that Tacoma covered its sale of the Centralia plant with equally available, long-term resources.

[50] June 25 Order at PP 44-46.

purchasers have relied since the enactment of the FPA. California State Parties argue that the Commission balanced the same factors in the California refund proceeding and reached the opposite conclusion. Further, they contend that during the refund period there was an enormous transfer of wealth from buyers to sellers, and that mitigated prices are more than sufficient to induce investment, while denying the windfall profits enjoyed by sellers.

Commission Determination

54. The Commission concluded in the June 25 Order that the massive revision of bilateral contracts that would be required to provide a refund remedy for market participants in the Pacific Northwest would create an unacceptable amount of risk and uncertainty for future market participants in the region, since it would set a precedent that the contract price for power may always be subject to change – without any advanced warning.[51] While, in fact, the record before the ALJ supports our conclusion,[52] this proposition does not require specific support from the record.[53] Thus, the Commission engaged in

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[51] As discussed above, the Puget complaint was dismissed before the potential refund period would have started and not "resurrected" until afterward. This fact also differentiates the Puget proceeding from the California refund proceeding.

[52] *See ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,384, and exhibits cited therein.

[53] *See* Order No. 888, *FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996* ¶ 31,036, at p. 31,682 (1996), *order on reh'g*, Order No. 888-A, *FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000* ¶ 31,048, at p. 30,210 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 688

a proper exercise of its discretion in considering the adverse consequences of the proposed remedy as a factor in denying refunds.

55. The Commission is not persuaded by the argument that denying refunds will do equal, if not more, damage to the regional spot market. It is unlikely that purchasers would completely opt out of a market that serves an important purpose of providing a source for power "on the spot," although it would be prudent for purchasers to be wary of overly-relying on the spot market. Further, while the Port makes allegations of lawlessness in the market-place, no evidence of such "lawlessness" has been shown with regard to any specific transaction in the Pacific Northwest spot market that is at issue in this proceeding. Accordingly, the request for rehearing on this issue is denied.[54]

4. *Ripple Claims*[55]

56. The June 25 Order, *citing* to the ALJ's proposed findings, noted that it is estimated that electricity in

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(D.C. Cir. 2000), *aff'd sub nom., New York v. FERC*, 122 S. Ct. 1012 (2002), *quoting Associated Gas Distributors v. FERC*, 824 F.2d 981, 1008 (D.C. Cir. 1987) ("Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall").

[54] A disgorgement remedy, as proposed by City of Seattle, is beyond the scope of Puget's complaint which is the sole basis for this proceeding.

[55] The ALJ explained "ripple claims" as "sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund." *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,300. Ripple claims were not entertained in the preliminary evidentiary hearing. Rather, the ALJ ruled that all parties reserved their right to pursue such claims if it was determined that such parties are liable for refunds. *Id.*

the region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain, and that approximately 500,000 transactions would have to be recalculated if refunds were directed.[56] Further, the recovery of refund claims would likely not be possible in many instances due to complications such as the large number of transactions not subject to Commission jurisdiction, difficulties in tracing upstream sellers and the difficulty of matching a sale with a particular source because most market participants rely on a portfolio of resources. Thus, while the unraveling of the massive volume of transactions necessary to determine potential refunds would require prolonged time and effort, in the end a fair result would likely not be achieved.

57. On rehearing, Tacoma, Port and others argue that the Commission erred in declining to order refunds because of the difficulty involved in making the necessary calculations. They claim that this is not a permitted consideration under the FPA. Moreover, they contend that the calculation of refunds would not be difficult. They point out that refund claimants in the preliminary evidentiary proceeding were able to submit their net claims with substantiating documentation within days of the ALJ's request, and suggest that all parties are capable of doing the same. City of Seattle contends that market participants have the necessary information readily available and that refunds could be determined in one simultaneous reconciliation. Grays Harbor claims that the calculation of ripple claims for its single contract at issue would not be complicated. California State Parties argue that the Commission's finding is based

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[56] June 25 Order at P 47.

on speculation, noting that the ALJ reserved the issue of ripple claims for a future phase of the proceeding and that there is no witness testimony that the magnitude of transactions would make it impossible to unwind fairly the chain of transactions.

58. California State Parties, Tacoma, and others posit that refunds could be calculated without difficulty if the Commission were to adopt a market clearing price or "benchmark" approach modeled after the refund methodology applied in the California refund proceeding. They claim that, once the market clearing price is fixed, it is a simple math process to apply the clearing price to each transaction. City of Seattle states that the ALJ's concerns regarding the impossibility of tracing upstream sellers would not be relevant since, under the clearing price approach, there is no reason to match a particular sale of power with a prior transaction involving the same power. It also argues that the Commission's concerns regarding the time and effort involved in calculating refunds is a "hollow excuse" because the calculation of refunds for the Pacific Northwest should be no more difficult than the calculation already made in the California refund proceeding. California State Parties state that the Commission decided, in denying Automated Power Exchange's (APX's) request (in the California refund proceeding) that the Commission impose refund liability on its upstream customers, that a seller is liable for the refunds associated with sales it made, without regard to the fact that the seller itself may have made no profit on the sales.[57] They ask that the Commission apply this same approach to the

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[57] *Citing San Diego Gas & Electric Co., et al.*, 102 FERC ¶ 61,317, at P 5, Sub-paragraph GG (2003).

current proceeding, in which case the Commission should not even concern itself with ripple claims.

Commission Determination

59. While the ALJ reserved the right of parties to pursue specific ripple claims in a future phase of the proceeding if necessary, the impact of ripple claims was addressed by witness testimony,[58] on which the ALJ relied in making her proposed findings.[59] The time and resources that must be devoted to refund calculations is a legitimate consideration within the Commission's discretion. The June 25 Order concluded not only that the massive undertaking would require prolonged time and effort, but in the end a fair result would not be achieved.

60. The June 25 Order pointed to specific difficulties in attempting to calculate refunds. On rehearing, parties did not address these specific problems but rather suggest that they could be avoided by using a benchmark approach similar to that used in the California refund proceeding.[60] That proceeding has proved to be extraordinarily time and resource consuming, raising myriads of issues and involving 18 months of proceedings before an ALJ. This can hardly be held out as the model to be applied to other proceedings. Also, parties have not adequately ex-

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[58] *E.g.*, Exh. BPA-1 at 19-21; PWX-1 at 15-18.

[59] *ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,385, and proposed findings 44 and 45.

[60] Tacoma contends that it readily produced the purchase data directed by the ALJ. However, it appears that the refund claimants' data was deficient, as it failed to provide the date and hour when each transaction was entered into, failed to reveal whether the power purchased was used to serve retail load or was resold, and failed to identify upstream vendors. *ALJ Recommendations*, 96 FERC ¶ 63,004, at p. 63,353, n.204.

plained why it is appropriate to apply a clearing price approach in a market that is based on bilateral contracts, and has no centralized clearing price. Nor have the parties advocating such an approach adequately explained how this solves the unfairness that results from our inability to exercise jurisdiction over transactions involving governmental entities.

61. There is no basis for rejecting ripple claims as suggested by the California State Parties. First, the Commission has granted rehearing regarding APX's liability in the California refund proceeding and determined that the APX and sellers into the APX will be jointly and severally liable for refund liability in the ISO and PX markets.[61] This decision was based on equitable considerations that are unique to that proceeding and provide no precedent for this proceeding. More fundamentally, Puget's complaint is directed at protecting the regional market and provides no basis for limiting refunds to a few market participants that chose to assert claims in the preliminary hearing. Such an approach would exacerbate the inequity of attempting to make the market whole.

5. *Number of Refund Claimants*

62. The June 25 Order noted that, of the hundreds of market participants in the region, only a handful of entities have chosen to pursue refund claims.[62] Further, most parties to the proceeding have chosen not to pursue their claims, including some that were net purchasers during the relevant period of time.

63. Tacoma, City of Seattle, Port and California State Parties argue that the number of refund claimants and the number of market participants that

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[61] *San Diego Gas & Electric Co.*, 105 FERC ¶ 61,066 (2003).

[62] June 25 Order at P 52.

chose not to pursue refunds is not relevant to the issue of whether refunds are warranted. They claim that the Commission engaged in speculation as to the reason why market participants chose not to pursue a claim. City of Seattle contends that the Commission may not deny refunds simply because only a few request relief.[63] The Port claims that the Commission's numbers are wrong because some WSPP members were not active market participants during the relevant period of time.

Commission Determination

64. The Commission agrees that a head count of the number of parties pursuing refund claims is not in itself relevant to whether refunds are warranted. The point of the June 25 Order was that, in a bilateral market with over 200 participants, our decision that requiring refunds in these circumstances would be inequitable is consistent with the decision of the overwhelming share of market participants foregoing refunds. This point is, of course, not determinative of our decision. Even apart from this point, we believe, based on the totality of the circumstances, the proceeding should be terminated because it is not possible to fashion a remedy that would be equitable to all the market participants in the Pacific Northwest.

F. *Mirant Bankruptcy*

65. On September 12, 2003, the Bankruptcy Court for the Northern District of Texas issued a "Temporary Restraining Order Against the Federal Energy Regulatory Commission" ("TRO") in *In re Mirant Corp. (Mirant Corp. v. FERC)*, Adversary Proceeding

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[63] *Citing Exxon Co., U.S.A. v. FERC*, 182 F.3d at 50 (the agency cannot simply take a "head count" among the parties in a contested settlement to decide whether it is fair).

No. 03-4355, which enjoins the Commission "from taking any action, directly or indirectly, to require or coerce the [Mirant] Debtors to abide by the terms of any Wholesale Contract [to which a Mirant Debtor is a party] which Debtors are substantially performing or which Debtors are not performing pursuant to an order of the Court unless FERC shall have provided the Debtors with ten (10) days' written notice setting forth in detail the action which FERC seeks to take with respect to any Wholesale Contract which is the subject of this paragraph."

66. Should the TRO be converted into a preliminary injunction, an action that the Commission opposes, the Commission will appeal that order. Despite the Commission's disagreement with the validity of the TRO and its expectation that the TRO (or a preliminary injunction) will be vacated on appeal, the Commission must comply with it until vacated. The TRO requires ten days' written notice before the Commission takes a proscribed action with respect to a covered Mirant Wholesale Contract. Accordingly, to the extent that this Order requires Mirant to act in a manner proscribed by the TRO, the Order will provide written notice to Mirant of the action that FERC will take with respect to a covered Mirant Wholesale Contract, which action will not become effective until ten (10) days after issuance of this Order. In all other respects, this Order is effective immediately.

The Commission orders:

The requests for rehearing are hereby denied, as discussed in the body of this order.

Commissioner Massey dissenting with a separate statement attached.

Commissioner Brownell concurring with a separate statement attached.

William L. MASSEY, Commissioner, *dissenting:*

I dissented from the underlying order and nothing in today's order persuades me to change my mind. I would set a refund effective date of December 25, 2000 and order refunds for spot market transactions (defined as one month or less) through June 20, 2001. I would use the MMCP methodology established in the California refund proceeding as a benchmark for just and reasonable spot market rates in the Northwest.

For the reasons set out in my dissent to the underlying order, I dissent from today's order.

Nora Mead BROWNELL, Commissioner, *concurring:*

1. This order sets forth the equity basis for denying refunds. While I agree with that analysis, my reading of the law dictates a stand-alone bar to ordering refunds, regardless of whether the equities warrant them. As the ALJ noted, the majority of the transactions at issue in this case were bilateral contracts under the standard WSPP Agreement.[1] The Commission has already concluded in other proceedings that modifications to contracts under the WSPP Agreement are subject to the *Mobile-Sierra* public interest standard of review.[2] I agree with the ALJ's

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[1] *Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy, et al.*, 96 FERC ¶ 63,044, at p. 65,387 (2001).

[2] *PacifiCorp v. Reliant Energy Services, Inc., et al.*, 103 FERC ¶ 61,355 (2003); *Nevada Power Company and Sierra Pacific*

finding that the refund claimants have not met that standard here.[3]

Power Company v. Duke Energy Trading and Marketing, L.L.C., 103 FERC ¶ 61,353 (2003).

[3] 96 FERC at p. 65,384.

FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Docket Nos. EL01-10-000, EL01-10-011, and EL01-10-014

Order Denying Request for Rehearing

(Issued Feb. 9, 2004)

Before Commissioners: Pat Wood, III, Chairman; Nora Mead Brownell, and Joseph T. Kelliher.

1. This order denies the People of the State of California *ex rel.* Bill Lockyer, Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission's (California State Parties) request for rehearing. The order finds that the Commission properly concluded that the bilateral transactions of the California Energy Resources Scheduling Division (CERS) of the California Department of Water Resources (CDWR) are outside the scope of this proceeding.

2. This order benefits customers because it will provide greater certainty and stability in the Pacific Northwest electricity spot markets.

Background

3. On October 26, 2000, Puget Sound Energy, Inc. (Puget) filed a complaint asking that the Commission order a cap on the prices at which sellers subject to the Commission's jurisdiction, including sellers of energy or capacity under the Western Systems Power Pool (WSPP) Agreement, could sell energy or capac-

ity into the Pacific Northwest's wholesale power markets. On December 15, 2000, the Commission dismissed Puget's complaint[1] but subsequently ordered a preliminary evidentiary hearing before an Administrative Law Judge (ALJ) to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest region. The Commission also set for preliminary evidentiary hearing the calculation of any refunds associated with such charges but did not establish a refund effective date.[2]

4. On September 24, 2001, the ALJ issued her recommendations and findings of fact, in which she recommended that no refunds were warranted for wholesale power sales in the Pacific Northwest between December 25, 2000 and June 20, 2001.[3] Among other things, she recommended that the California State Parties claim for refunds of CERS bilateral transactions should not be considered in the proceeding since they involved sales into California and not the Pacific Northwest. She explained that Puget's complaint referred specifically to a price cap on sales of capacity and energy "into" the Pacific Northwest. However, she found that southbound wholesale sales of power at the California-Oregon Border (COB) and Nevada-Oregon Border (NOB) interconnections were not within the Pacific Northwest because the delivery point was not to a Pacific

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[1] *San Diego Gas & Electric Company, et al.*, 93 FERC ¶ 61,294 (2000).

[2] *San Diego Gas & Electric Company, et al.*, 96 FERC ¶ 61,120, at pp. 61,499-500 (December 15 Order).

[3] *Puget Sound Energy, Inc., et al.*, 96 FERC ¶ 63,044 (2001) (*ALJ Recommendations*).

Northwest load server and because deliveries actually took place in California. Therefore, she concluded that since the bilateral transactions involving CERS were sales into California, not into the Pacific Northwest, the CERS transactions were outside the scope of this proceeding. Moreover, the ALJ noted that the Commission declined to order refunds with respect to these same agreements in the California refund proceeding or Docket No. EL00-95.[4]

5. On June 25, 2003, the Commission addressed Puget's request for rehearing of the December 15 Order in which the Commission dismissed Puget's complaint. In the June 25 Order, the Commission stated that the relief that Puget requested had already been provided in a prior Commission order, and terminated the proceeding.[5]

6. On November 10, 2003, the Commission denied requests for rehearing of the June 25 Order.[6] Among other things, the Commission noted in a footnote that the ALJ, in determining the proper definition of "Pacific Northwest" for purposes of this proceeding, recommended that the California State Parties claims for refunds of CERS bilateral transactions should not be considered in the proceeding. The Commission reiterated the ALJ's findings that the bilateral transactions involving CERS were sales into California and not into the Pacific Northwest. The Commission stated that the ALJ's definition of Pacific Northwest and her conclusion that the CERS transactions were

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[4] *Id.* at pp. 65,331-332.

[5] *Puget Sound Energy, Inc. v. All Jurisdictional Sellers, et al.*, 103 FERC ¶ 61,348 (2003) (June 25 Order).

[6] *Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy, et al.*, 105 FERC ¶ 61,183 (2003) (November Order).

outside the scope of this proceeding were reasonable and supported by the record, and adopted the ALJ's proposed findings and recommendations on these matters.[7]

Request for Rehearing

7. On December 10, 2003, the California State Parties filed a request for rehearing of the November Order. They argue that the Commission erred by finding that the California State Parties could not recover refunds for purchases made by CERS. They contend that the Puget complaint supports their position because Puget's focus was on transactions consummated in the Pacific Northwest market and not on where the power transacted in that market would ultimately be consumed. Moreover, they argue that CERS' case must be judged based on the location of the financial transfer, *i.e.*, the Pacific Northwest delivery point.

8. In addition, they assert that there can be no doubt that the refund claim at issue involves purchases of power made by CERS in the Pacific Northwest at Pacific Northwest delivery points because the CERS transactions were made predominately at COB and the NOB interconnections, and the COB and NOB interconnections are within the Pacific Northwest. Therefore, they argue that factually there can be no question that the CERS transactions that form the basis for the California State Parties' refund claim in this case occurred within the Pacific Northwest, contrary to the ALJ's findings.

9. Finally, they maintain that if the Commission denies refunds generally, the Commission should make explicit that if refunds were granted, CERS'

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[7] *Id.* at P 42, note 43.

bilateral purchases in the Pacific Northwest spot market would be subject to mitigation in the same way that purchases by Pacific Northwest municipal utilities are subject to mitigation.

Discussion

10. We deny the California State Parties request for rehearing. Essentially, they claim that the Commission erred by accepting the ALJ's conclusion that refund claims based on CERS' purchases cannot properly be considered in this proceeding because they do not involve transactions "into" the Pacific Northwest. They claim that Puget's complaint and the evidence in the record supports their position.

11. Contrary to the California State Parties' assertion, we find that Puget's complaint supports the ALJ's conclusion that the CERS' transactions are outside the scope of this proceeding. In its complaint, Puget requested "an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of capacity and energy under the Western Systems Power Pool Agreement ("WSPP"), may sell capacity or energy into the Pacific Northwest's wholesale power markets."[8] Clearly, Puget's complaint focus was on transactions into the Pacific Northwest, and as the ALJ explained, the bilateral transactions involving CERS were sales into California and not into the Pacific Northwest.

12. Although the California State Parties contend that the CERS transactions involved purchases of power in the Pacific Northwest at Pacific Northwest delivery points, we find that the ALJ reviewed the evidence and concluded that the southbound transactions at NOB and COB are not serving load in the

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[8] Puget's complaint at 1-2 (footnote omitted).

Pacific Northwest but are serving California load.[9] Furthermore, we note that California State Parties' witness testified that COB deliveries are made at the California border and that the California ISO tariff specifies scheduling point for such deliveries at California substations.[10] Moreover, NOB deliveries occur in California at the control area of the Los Angeles Department of Water and Power.[11] Therefore, in the November Order, we properly found that the ALJ's conclusion that the CERS transactions did not involve sales into the Pacific Northwest was reasonable and supported by evidence in the record.

13. Finally, since we find that the CERS' bilateral purchases are not within the scope of this proceeding we will deny the California State Parties' request that the Commission should make explicit that CERS' bilateral purchases in the Pacific Northwest spot market would be subject to mitigation in the same way that purchases by Pacific Northwest municipal utilities are subject to mitigation. The CERS' purchases must be treated differently from the purchases by the Pacific Northwest municipal utilities since only the latter are within the scope of the complaint.

The Commission orders:

The California State Parties' request for rehearing is hereby denied, as discussed in the body of this order.

Commissioner Kelly not participating.

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[9] *See ALJ Recommendations*, 96 FERC ¶ 63,044, at p. 65,307.

[10] Transcript at 876. *ALJ Recommendations*, at p. 65,312 and Proposed Findings of Fact 2 and 28.

[11] Transcript at 876.

UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

Nos. 03-74139, 03-74472, 03-74769,
04-70110, 04-70185, 04-70703, 04-71189

PORT OF SEATTLE, WASHINGTON, ET AL.,
Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

[April 9, 2009]

ORDER

Before: THOMAS, McKEOWN and CLIFTON, Circuit Judges.

The panel has voted to deny the petitions for rehearing and rehearing en banc, filed December 17, 2007. The full court has been advised of the suggestion for rehearing en banc, and no judge of the court has requested a vote on the suggestion for rehearing en banc. Fed. R. App. P. 35(b). The petitions for rehearing and rehearing en banc are denied.

STATUTORY PROVISIONS INVOLVED

The Federal Power Act, 16 U.S.C. §§ 791a *et seq.*, provides in relevant part:

Section 206 of the Federal Power Act, 16 U.S.C. § 824e, provides:

16 U.S.C. § 824e. Power of Commission to fix rates and charges; determination of cost of production or transmission

(a) Unjust or preferential rates, etc.; statement of reasons for changes; hearing; specification of issues

Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affected such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by

order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Refund effective date; preferential proceedings; statement of reasons for delay; burden of proof; scope of refund order; refund orders in cases of dilatory behavior; interest

Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date of the filing of such complaint nor later than 5 months after the filing of such complaint. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the publication date. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 824d of this title and otherwise act as speedily as possible. If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the pe-

riod subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: Provided, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Refund considerations; shifting costs; reduction in revenues; "electric utility companies" and "registered holding company" defined

Notwithstanding subsection (b) of this section, in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) of this section shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding

company: Provided, That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended [15 U.S.C. 79 et seq.].

(d) Investigation of costs

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

(e)(1) In this subsection:

(A) The term "short-term sale" means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts subject to automatic renewal).

(B) The term "applicable Commission rule" means a Commission rule applicable to sales at wholesale by public utilities that the Commission determines after notice and comment should also be applicable to entities subject to this subsection.

(2) If an entity described in section 824(f) of this title voluntarily makes a short-term sale of electric energy through an organized market in which the rates for the sale are established by Commission-approved tariff (rather than by contract) and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of the sale, the entity shall be subject to the refund authority of the Commission under this section with respect to the violation.

(3) This section shall not apply to –

(A) any entity that sells in total (including affiliates of the entity) less than 8,000,000 megawatt hours of electricity per year; or

(B) an electric cooperative.

(4)(A) The Commission shall have refund authority under paragraph (2) with respect to a voluntary short term sale of electric energy by the Bonneville Power Administration only if the sale is at an unjust and unreasonable rate.

(B) The Commission may order a refund under subparagraph (A) only for short-term sales made by the Bonneville Power Administration at rates that are higher than the highest just and reasonable rate charged by any other entity for a short-term sale of electric energy in the same geographic market for the same, or most nearly comparable, period as the sale by the Bonneville Power Administration.

(C) In the case of any Federal power marketing agency or the Tennessee Valley Authority, the Commission shall not assert or exercise any regulatory authority or power under paragraph (2) other than the ordering of refunds to achieve a just and reasonable rate.

Section 307 of the Federal Power Act, 16 U.S.C. § 825f, provides:

§ 825f. Investigations by Commission

(a) Scope

The Commission may investigate any facts, conditions, practices, or matters which it may find necessary or proper in order to determine whether any person, electric utility, transmitting utility, or other entity has violated or is about to violate any provision of this chapter or any rule, regulation, or order thereunder, or to aid in the enforcement of the provisions of this chapter or in prescribing rules or regulations thereunder, or in obtaining information to serve as a basis for recommending further legislation concerning the matters to which this chapter relates, or in obtaining information about the sale of electric energy at wholesale in interstate commerce and the transmission of electric energy in interstate commerce. The Commission may permit any person, electric utility, transmitting utility, or other entity to file with it a statement in writing under oath or otherwise, as it shall determine, as to any or all facts and circumstances concerning a matter which may be the subject of investigation. The Commission, in its discretion, may publish or make available to State commissions information concerning any such subject.

(b) Attendance of witnesses and production of documents

For the purpose of any investigation or any other proceeding under this chapter, any member of the Commission, or any officer designated by it, is empowered to administer oaths and affirmations, subpena witnesses, compel their attendance, take

evidence, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records which the Commission finds relevant or material to the inquiry. Such attendance of witnesses and the production of any such records may be required from any place in the United States at any designated place of hearing. Witnesses summoned by the Commission to appear before it shall be paid the same fees and mileage that are paid witnesses in the courts of the United States.

(c) Resort to courts of United States for failure to obey subpena; punishment

In case of contumacy by, or refusal to obey a subpena issued to, any person, the Commission may invoke the aid of any court of the United States within the jurisdiction of which such investigation or proceeding is carried on, or where such person resides or carries on business, in requiring the attendance and testimony of witnesses and the production of books, papers, correspondence, memoranda, contracts, agreements, and other records. Such court may issue an order requiring such person to appear before the Commission or member or officer designated by the Commission, there to produce records, if so ordered, or to give testimony touching the matter under investigation or in question; and any failure to obey such order of the court may be punished by such court as a contempt thereof. All process in any such case may be served in the judicial district whereof such person is an inhabitant or wherever he may be found or may be doing business. Any person who willfully shall fail or refuse to attend and testify or to answer any lawful inquiry or to produce books, papers, correspondence, memoranda, contracts, agreements, or other records, if in his or its power so to do, in obedience to

the subpena of the Commission, shall be guilty of a misdemeanor and, upon conviction, shall be subject to a fine of not more than $1,000 or to imprisonment for a term of not more than one year, or both.

(d) Testimony by deposition

The testimony of any witness may be taken, at the instance of a party, in any proceeding or investigation pending before the Commission, by deposition, at any time after the proceeding is at issue. The Commission may also order testimony to be taken by deposition in any proceeding or investigation pending before it, at any stage of such proceeding or investigation. Such depositions may be taken before any person authorized to administer oaths not being of counsel or attorney to either of the parties, nor interested in the proceeding or investigation. Reasonable notice must first be given in writing by the party or his attorney proposing to take such deposition to the opposite party or his attorney of record, as either may be nearest, which notice shall state the name of the witness and the time and place of the taking of his deposition. Any person may be compelled to appear and depose, and to produce documentary evidence, in the same manner as witnesses may be compelled to appear and testify and produce documentary evidence before the Commission, as hereinbefore provided. Such testimony shall be reduced to writing by the person taking the deposition, or under his direction, and shall, after it has been reduced to writing, be subscribed by the deponent.

(e) Deposition of witness in a foreign country

If a witness whose testimony may be desired to be taken by deposition be in a foreign country, the deposition may be taken before an officer or person designated by the Commission, or agreed upon by the

parties by stipulation in writing to be filed with the Commission. All depositions must be promptly filed with the Commission.

(f) Deposition fees

Witnesses whose depositions are taken as authorized in this chapter, and the person or officer taking the same, shall be entitled to the same fees as are paid for like services in the courts of the United States.

Section 309 of the Federal Power Act, 16 U.S.C. § 825h, provides:

§ 825h. Administrative powers of Commission; rules, regulations, and orders

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this chapter; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed. Unless a different date is specified therein, rules and regulations of the Commission shall be effective thirty days after publication in the manner which the Commission shall prescribe. Orders of the Commission shall be effective on the date and in the manner which the Commission shall prescribe. For the pur-

poses of its rules and regulations, the Commission may classify persons and matters within its jurisdiction and prescribe different requirements for different classes of persons or matters. All rules and regulations of the Commission shall be filed with its secretary and shall be kept open in convenient form for public inspection and examination during reasonable business hours.

Supreme Court of the United States
Office of the Clerk
Washington, DC 20543-0001

WILLIAM K. SUTER
Clerk of the Court
(202) 479-3011

June 29, 2009

Mr. David C. Frederick
Kellogg, Huber, Hansen, Todd,
Evans & Figel, P.L.L.C.
1615 M Street, N.W.
Suite 400
Washington, D.C. 20036

Re: Puget Sound Energy, Inc., et al.
v. California, et al.
Application No. 08A1163

Dear Mr. Frederick:

The application for an extension of time within which to file a petition for a writ of certiorari in the above-entitled case has been presented to Justice Kennedy, who on June 29, 2009 extended the time to and including September 4, 2009.

This letter has been sent to those designated on the attached notification list.

Sincerely,

William K. Suter, Clerk
by /s/ RUTH JONES

Ruth Jones
Case Analyst

[attached notification list omitted]

SUPREME COURT, U.S.
FILED

No. 09-288

In the Supreme Court of the United States

PUGET SOUND ENERGY, INC., ET AL., PETITIONERS

v.

STATE OF CALIFORNIA, ET AL.

ON PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

BRIEF FOR THE FEDERAL ENERGY REGULATORY COMMISSION IN OPPOSITION

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QUESTIONS PRESENTED

1. Whether the court of appeals had jurisdiction to review a proceeding to investigate the reasonableness of rates for electric energy under 16 U.S.C. 824e, in which the Federal Energy Regulatory Commission held an evidentiary hearing, took recommendations from an administrative law judge, held oral argument, and issued orders denying refunds.

2. Whether the court of appeals erred in failing to defer to the Federal Energy Regulatory Commission's decision to address various issues arising from the California energy crisis by conducting separate supplier-specific enforcement proceedings under 16 U.S.C. 825h, rather than reopening a generic refund proceeding under 16 U.S.C. 824e.

3. Whether the court of appeals erred in failing to defer to the Federal Energy Regulatory Commission's interpretation of the scope of a complaint.

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In the Supreme Court of the United States

No. 09-288

PUGET SOUND ENERGY, INC., ET AL., PETITIONERS

v.

STATE OF CALIFORNIA, ET AL.

ON PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

BRIEF FOR THE FEDERAL ENERGY REGULATORY COMMISSION IN OPPOSITION

OPINIONS BELOW

The opinion of the court of appeals (Pet. App. 1a-37a) is reported at 499 F.3d 1016. The orders of the Federal Energy Regulatory Commission (Pet. App. 378a-408a, 409a-447a, 448a-453a) are reported at 103 F.E.R.C. ¶ 61,348, 105 F.E.R.C. ¶ 61,183, and 106 F.E.R.C. ¶ 61,109.

JURISDICTION

The judgment of the court of appeals was entered on August 24, 2007. The petitions for rehearing were denied on April 9, 2009 (Pet. App. 454a). On June 29, 2009, Justice Kennedy extended the time within which to file a petition for a writ of certiorari to and including Sep-

tember 4, 2009, and the petition was filed on that date. The jurisdiction of this Court is invoked under 28 U.S.C. 1254(1).

STATEMENT

1. The Federal Power Act (FPA or Act), 16 U.S.C. 791a *et seq.*, grants the Federal Energy Regulatory Commission (FERC or Commission) exclusive jurisdiction over the "transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce" by public utilities. 16 U.S.C. 824(b)(1). Under the FPA, proposed rates for the sale or transmission of power within FERC's jurisdiction must be "just and reasonable" and not unduly discriminatory or preferential. 16 U.S.C. 824d(a) and (b).

The Act also provides for the Commission to review rates after they have been accepted for filing and gone into effect. If, after a hearing—either on its own motion or based on a complaint –the Commission determines that any existing rate or charge is "unjust, unreasonable, unduly discriminatory or preferential," it must determine and fix by order "the just and reasonable rate * * * to be thereafter observed and in force." 16 U.S.C. 824e(a). The relief allowed under 16 U.S.C. 824e is temporally limited: FERC may order refunds only for rates collected after the "refund effective date"; during the period at issue in this case, that date could be set no earlier than 60 days after the filing of a complaint. 16 U.S.C. 824e(b) (2000).

Under 16 U.S.C. 825h, the Commission also has authority to remedy tariff violations through enforcement proceedings. Section 825h grants the Commission "power to perform any and all acts, and to prescribe,

issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this [Act]." 16 U.S.C. 825h. The Commission may use its authority under Section 825h to require disgorgement or other remedies if a seller is found to have violated the terms of its rate authority, or rules or orders of the Commission.

2. This case arises out of the 2000-2001 energy crisis in the western United States. See generally *Morgan Stanley Capital Group Inc.* v. *Public Util. Dist. No. 1*, 128 S. Ct. 2733 (2008); *California ex rel. Lockyer* v. *FERC*, 383 F.3d 1006 (9th Cir. 2004), cert. denied, 551 U.S. 1140 (2007). During the western energy crisis, the price of electricity in the Pacific Northwest rose dramatically. Pet. App. 9a. In October 2000, petitioner Puget Sound Energy, Inc. (Puget) filed a complaint with the Commission, seeking an order limiting the prices at which sellers subject to FERC's jurisdiction could sell electricity into the Pacific Northwest's wholesale power markets. *Id.* at 10a-11a. On December 15, 2000, the Commission dismissed the complaint. *Id.* at 11a; *San Diego Gas & Elec. Co.* v. *Sellers of Energy & Ancillary Servs.*, 93 F.E.R.C. ¶ 61,294. The Commission explained that implementation of the "region-wide price cap" sought by Puget would be "impracticable given the market structure in the Northwest." *Id.* at 62,019.

Puget sought rehearing before the Commission. While its request was pending, the Commission imposed price caps on all sales in all western spot markets. *San Diego Gas & Elec. Co.* v. *Sellers of Energy & Ancillary Serv.*, 95 F.E.R.C. ¶ 61,418 (2001). Following that decision, Puget moved to withdraw both its complaint and its request for rehearing of the December 15, 2000 order

dismissing its complaint. Various parties opposed the withdrawal motion. Pet. App. 11a-12a.

In July 2001, acting on its own initiative, the Commission instituted a separate proceeding to consider past spot-market sales in the Pacific Northwest. Pet. App. 38a-110a. The Commission did not invoke 16 U.S.C. 824e to determine whether to change the rates on file. Instead, it explained that the "preliminary evidentiary proceeding" was "intended to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001," with the aim of "determin[ing] the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest." Pet. App. 102a-103a.

After discovery and an evidentiary hearing, an administrative law judge (ALJ) recommended against ordering refunds for such sales. Pet. App. 326a. The evidence demonstrated that the Pacific Northwest market for spot sales of electricity was competitive and functional during the relevant time period and that prices were not unreasonable. *Ibid.* While California electric energy prices affected electric energy prices in the Pacific Northwest, other factors contributed to higher prices in the Pacific Northwest, including reduced hydroelectric power due to drought, increased demand, and high natural-gas prices. *Id.* at 322a. The ALJ also recommended that the Commission affirm its dismissal of Puget's complaint and allow Puget to withdraw its rehearing request. *Id.* at 365a.

3. In June 2003, the Commission denied Puget's motion to withdraw its complaint and granted its request

for rehearing of the December 2000 dismissal of its complaint. The Commission reiterated that it had provided all the relief sought by Puget in its complaint when the Commission implemented price caps on wholesale spot-market sales throughout the West. Pet. App. 387a-390a. Based on an examination of the "totality of the circumstances," the Commission also determined that even if it were to conclude that prices during the potential refund period were unjust and unreasonable, "the directing of refunds in this proceeding would not result in an equitable resolution of the matter." *Id.* at 401a-402a. Accordingly, the Commission terminated the proceeding.

On the same day, the Commission initiated enforcement proceedings relating to Enron's market-manipulation strategies, which had come to light the year before. *American Elec. Power Serv. Corp.*, 103 F.E.R.C. ¶ 61,345 (2003); *Enron Power Mktg., Inc.*, 103 F.E.R.C. ¶ 61,346 (2003). The Commission directed dozens of entities, including several Pacific Northwest sellers, to show cause why their conduct did not constitute market manipulation in violation of applicable tariffs. *American Elec. Power Serv. Corp., supra.* It further directed agency ALJs to recommend appropriate remedies for any unjust enrichment by those entities. 103 F.E.R.C. at 62,328. And it instituted another evidentiary proceeding to address allegations that another set of sellers engaged in gaming or other market-manipulation practices in concert with other market participants. *Enron Power Mktg., Inc., supra.*[1]

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[1] By 2005, the Commission had "completed all but one of the 60 investigations regarding market manipulation" that were instituted in these orders. FERC Report to Congress, *The Commission's Response to the California Electricity Crisis and Timeline for Distributions of*

4. The Commission later denied a request for rehearing of its decision not to award refunds for sales in the Pacific Northwest. Pet. App. 409a-447a. In a separate order, it denied a rehearing request filed by California and some of its agencies. *Id.* at 448a-453a. The Commission clarified that bilateral transactions involving the California Energy Resources Scheduling Division (CERS) of the California Department of Water Resources were outside the scope of the Pacific Northwest proceeding. The Commission agreed with the ALJ that Puget's complaint concerned only wholesale power sales into the Pacific Northwest and that the evidence showed that the CERS transactions served only California load, not Pacific Northwest load. *Id.* at 452a-453a.

5. The court of appeals granted petitions for review. Pet. App. 1a-37a. The court rejected the Commission's argument that its decision to deny refunds was an exercise of unreviewable agency discretion under *Heckler* v. *Chaney*, 470 U.S. 821, 831 (1985), holding that *Heckler* is limited to "agency *refusals to institute* investigative or enforcement proceedings." Pet. App. 18a (quoting *Heckler*, 470 U.S. at 838). But where an agency has initiated proceedings, the court reasoned, there are meaningful standards for review and *Heckler* does not apply. Thus, the court continued, "where FERC has made a determination to adjudicate a dispute or take steps towards enforcing a violation of the law," the outcome it chooses is subject to review under the standards set forth in the Administrative Procedure Act, 5 U.S.C. 706. Pet. App. 18a. Here, because "FERC has held hearings and taken evidence to adjudicate a dispute between the

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Refunds 3 (Dec. 27, 2005) <http://www.ferc.gov/legal/staff-reports/comm-response.pdf>.

parties as to whether refunds should be awarded" in the Pacific Northwest, the court held that the agency's decision was reviewable under the same standards that govern review of other grants or denials of refunds. *Id.* at 18a-19a.

The court of appeals rejected FERC's determination that CERS purchases in the Pacific Northwest spot market were outside the scope of the proceeding because Puget's complaint focused on sales of energy "into" the Pacific Northwest, whereas purchases made by CERS were sales "into" California. Pet. App. 29a-30a. The court concluded that substantial evidence in the record did not support the finding that energy purchased by CERS was physically delivered in California, and, in any event, the legal change of ownership occurred at interconnections located within the Pacific Northwest. *Id.* at 30a-31a. Further, although the court was "mindful" that it owed deference to FERC's interpretation of the complaint, the court nonetheless rejected FERC's interpretation because "[o]n its face, Puget's complaint provides no indication of an intent to exclude refunds for energy purchased in the Pacific Northwest spot market for consumption outside the geographical area." *Id.* at 31a. The court further concluded that FERC's interpretation of Puget's complaint was inconsistent with its interpretation of a similar complaint in the California refund proceeding. *Id.* at 32a.

The court of appeals also held that FERC had erred in failing to take into account evidence of market manipulation when it decided not to order refunds. Pet. App. 33a-36a. In particular, the court determined that FERC was required to reconsider the finding that the Pacific Northwest market was functional and competitive in light of the evidence adduced concerning manipulative

schemes in the California market involving Pacific Northwest sellers. *Id.* at 34a-35a. That evidence of market manipulation had led FERC to initiate separate enforcement proceedings in 2003. See p. 5, *supra*. The court of appeals rejected the argument that the need for reconsideration in these refund proceedings was obviated by FERC's decision to address market manipulation in the separate enforcement proceedings. Pet. App. 35a-36a. The court noted that the Commission had failed to rely on that rationale in its order, and, in any event, "FERC's prosecutorial investigations cannot justify the denial of relief in contested adjudications before the Commission." *Id.* at 36a. Accordingly, the court "remand[ed] to permit FERC to examine this new evidence of market manipulation in detail and account for it in any future orders regarding the award or denial of refunds in the Pacific Northwest proceeding." *Ibid.*

ARGUMENT

Petitioners argue (Pet. 12-23) that the court of appeals was precluded from reviewing the FERC order at issue in this case, which, they say, represented a discretionary decision not to initiate enforcement proceedings. The court of appeals reasonably concluded otherwise in the particular circumstances of this case, however, and its conclusion does not warrant review by this Court. The court of appeals reasoned that the Commission's decision in this case, reached after formal adversarial proceedings—including an evidentiary hearing—was subject to judicial review. Petitioners also object (Pet. 23-32) to several rulings by the court of appeals on procedural issues in the case concerning the scope of the refund proceedings and the discretion of the Commission to choose the manner in which it will pursue allega-

tions of violations. We agree that the court of appeals erred on those points. But those errors consist of the misapplication of correctly stated legal principles to the particular circumstances of this case, which arises out of the 2000-2001 western energy crisis, a highly unusual event that is unlikely to recur. See *CAlifornians for Renewable Energy* v. *California Pub. Utils. Comm'n*, 119 F.E.R.C. ¶ 61,058, at ¶ 30 (2007) (noting that "the 2000-2001 energy crisis in the West" was "an unprecedented situation in which numerous adverse events occurred simultaneously"); *id.* ¶¶ 31-41 (describing steps taken by the Commission "to ensure that there are appropriate market safeguards in place to prevent a repeat of the California 2000-2001 energy crisis"). Moreover, the court of appeals remanded for further proceedings and explanation by the Commission, and did not decide that refunds would be appropriate. Further review therefore is not warranted.

1. Petitioners contend (Pet. 12-23) that FERC's order in this case was not subject to judicial review. They rely on *Heckler* v. *Chaney*, 470 U.S. 821 (1985), which held that "an agency's decision not to prosecute or enforce, whether through civil or criminal process," is not subject to review. *Id.* at 831. Before the court of appeals, the Commission advanced a similar contention, arguing that its decision not to order refunds was analogous to a decision not to undertake enforcement action and therefore was immune from review under *Heckler*. Pet. App. 17a. But as the court of appeals observed, the Commission action at issue here can appropriately be characterized as an order resolving an adjudicatory proceeding rather than as a decision not to initiate enforcement proceedings. *Id.* at 18a. Here, the Commission ordered trial-type evidentiary hearings (with discovery,

testimony and cross-examination) before an ALJ, who presented findings and recommendations to the Commission, which later heard oral argument before issuing orders. *Id.* at 18a-19a. In this proceeding, unlike in a typical investigation related to enforcement proceedings, the Commission allowed affected persons to intervene and participate as parties in the trial-type evidentiary hearing. *Id.* at 50a-52a. The proceeding therefore had much in common with adjudicatory proceedings that usually are subject to judicial review, as distinguished from prosecutorial decisions that are not.

Significantly, moreover, as the court of appeals noted, the Commission did not simply decline to initiate an enforcement proceeding or a refund proceeding under 16 U.S.C. 824e; rather, it made a specific determination that refunds were not warranted in the Pacific Northwest. Pet. App. 18a-19a. And as the court of appeals also correctly noted, courts "regularly exercise judicial review over FERC's decision to grant or deny refunds." *Id.* at 19a. In any event, even if the court of appeals erred in its assessment of the agency's action in this somewhat unusual proceeding, that case-specific error would not warrant this Court's review.

Petitioners assert (Pet. 12-17) that the decision below conflicts not only with *Heckler* but also with various lower court decisions applying *Heckler*. But most of the cases relied on by petitioners involved agency actions that were indisputably prosecutorial or pre-enforcement actions. See, *e.g.*, *Heckler*, 470 U.S. at 824 (FDA refused to "take various [requested] investigatory and enforcement actions" or "recommend * * * prosecution" to address alleged statutory violations); *Association of Irritated Residents* v. *EPA*, 494 F.3d 1027, 1035 (D.C. Cir. 2007) (settlement of potential enforcement action by

consent agreement); *Greer* v. *Chao*, 492 F.3d 962, 963 (8th Cir. 2007) (agency investigated whether to take enforcement action against a government contractor and terminated the pre-enforcement action when the investigation was inconclusive as to violations); *Baltimore Gas & Elec. Co.* v. *FERC*, 252 F.3d 456, 457 (D.C. Cir. 2001) (FERC issued a "show cause" order and undertook a "non-public" enforcement investigation into violations of the Natural Gas Act, then settled the enforcement proceeding without resolving liability); *New York State Dep't of Law* v. *FCC*, 984 F.2d 1209, 1211-1212 (D.C. Cir. 1993) (on the basis of internal agency audits, FCC initiated an enforcement proceeding with a "show cause" order and terminated the proceeding on settlement, without resolving the legal issues); *Sherman* v. *Black*, 315 Fed. Appx. 347, 349 (2d Cir. 2009) (decision not to commence enforcement proceedings).

There are few, if any, analogous cases in which courts of appeals disclaimed authority to review formal agency orders that were preceded by the public, trial-type fact-finding proceeding that was conducted by the Commission in this case in response to the filing of a complaint. Petitioners point (Pet. 16) to *Sierra Club* v. *Larson*, 882 F.2d 128, 130-133 (4th Cir. 1989), which held that an agency's decision not to pursue "a formal penalty action" in response to a complaint was unreviewable, even though the agency had conducted a "fact-finding investigation," but there is no indication that the "investigation" in that case involved the kind of formal adversarial proceedings at issue here. Rather, the agency's decision appears to have been an ordinary exercise of prosecutorial discretion not to proceed with enforcement. This case therefore does not give rise to a conflict with the other decisions cited by petitioners,

which concerned judicial review of more traditional and typical prosecutorial decisions not to institute proceedings.

2. Petitioners are correct (Pet. 23-28) that the court of appeals erred in holding that the Commission was required to consider allegations of tariff violations in an adjudicatory rate proceeding initiated by a complaint under Section 824e, when the Commission was already addressing those allegations in an enforcement proceeding that it had initiated under 16 U.S.C. 825h. That aspect of the court's decision is contrary to *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Cos.*, 498 U.S. 211 (1991), which held that "[a]n agency enjoys broad discretion in determining how best to handle related, yet discrete issues in terms of procedures and priorities." *Id.* at 230 (citation omitted); see *ibid.* ("The court clearly overshot the mark if it ordered the Commission to resolve the take-or-pay problem in this proceeding," rather than "in a separate proceeding."); see also *Vermont Yankee Nuclear Power Corp.* v. *NRDC*, 435 U.S. 519, 543 (1978) ("Absent constitutional constraints or extremely compelling circumstances the administrative agencies should be free to fashion their own rules of procedure and to pursue methods of inquiry capable of permitting them to discharge their multitudinous duties.") (internal quotation marks and citation omitted); *GTE Serv. Corp.* v. *FCC*, 782 F.2d 263, 273-274 (D.C. Cir. 1986).

When presented with evidence of market manipulation adduced by its staff and market participants, the Commission decided to consider that evidence in separate, supplier-specific enforcement investigative proceedings concerning possible tariff violations, rather than to reopen generic rate-changing refund proceed-

ings that had been underway for years. FERC issued a package of orders on the same day in which it established an enforcement structure for addressing the different types of allegations arising from the energy crisis: (1) it instituted new enforcement proceedings under Section 825h to investigate allegations of tariff violations by individual sellers, *American Elec. Power Serv. Corp.*, 103 F.E.R.C. ¶ 61,345 (2003), and *Enron Power Mktg., Inc.*, 103 F.E.R.C. ¶ 61,346 (2003), and those bidding into California's centralized market, *Investigation of Anomalous Bidding Behavior & Practices*, 103 F.E.R.C. ¶ 61,347 (2003); and (2) it ended the adjudicatory proceeding under Section 824e initiated by Puget's complaint to determine the reasonableness of rates in the Pacific Northwest, finding that prospective rates were appropriately mitigated and that no refunds were warranted, Pet. App. 378a-403a. The next day, the Commission completed issuance of the package of orders by imposing conditions on market-based rate authority in a Commission-initiated proceeding under Section 824e. *Investigation of Terms & Conditions of Pub. Util. Market-Based Rate Authorizations*, 103 F.E.R.C. ¶ 61,349 (2003).

Nothing in Section 824e compels the Commission to consider any and all issues in a single adjudicatory rate proceeding. To the contrary, the statute contemplates that such a proceeding may be limited to particular issues. Section 824e(a) provides that "[i]f, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated." 16 U.S.C. 824e(a). As the D.C. Circuit has observed, in requiring that the Commission "specify the issues to be adjudicated," Section 824e

makes clear that these proceedings are designed to "identify and address such discrete issues." *Colorado Office of Consumer Counsel* v. *FERC*, 490 F.3d 954, 956 (2007), cert. denied, 128 S. Ct. 1872 (2008). Accordingly, in conducting a Commission-initiated investigation under Section 824e, the Commission was not required to adjudicate additional issues raised by parties. *Ibid.*; see *Mobil Oil*, 498 U.S. at 230.

Although the court of appeals erred in holding that the Commission was required to consider market-manipulation evidence in the Section 824e proceeding, that aspect of its decision does not warrant further review. The court rested its holding in part on its determination that the Commission had "fail[ed] to rely on this reasoning below," *i.e.*, that FERC had not explained, in its order, that consideration of market-manipulation evidence was unnecessary because that evidence was already being considered in a separate proceeding. Pet. App. 35a. The court's reasoning incorrectly assumes that the Commission has an obligation to explain the overall structure of its dockets in each order it issues. Nevertheless, the court proceeded from the fundamentally correct premise that an agency's decision may not be upheld on a ground on which the agency did not rely. See *SEC* v. *Chenery Corp.*, 318 U.S. 80, 88 (1943). The misapplication of that correctly stated rule of law to the particular set of orders at issue here does not warrant this Court's review. See Sup. Ct. R. 10. That is especially true in light of the interlocutory posture of this case, since the court remanded the case to the Commission but did not dictate what steps the Commission must take on remand and did not hold that refunds would ultimately be required. See *Hamilton-Brown Shoe Co.* v. *Wolf Bros. & Co.*, 240 U.S. 251, 258 (1916).

3. Finally, petitioners are correct (Pet. 28-32) that the court of appeals erred in construing Puget's complaint to include bilateral purchases in California, even though Puget—the party that drafted and filed the complaint—agreed with the Commission that its complaint concerning the Pacific Northwest did not address sales to California purchasers in that market. The court of appeals identified three reasons why FERC's determination that Puget's complaint did not encompass sales to California electricity users in the Pacific Northwest spot market was arbitrary and capricious.[2] First, the court defined the scope of the complaint by reference to what Puget did not explicitly *exclude*, rather than by reference to the violation it sought to remedy. Pet. App. 31a ("On its face, Puget's complaint provides no indication of an intent to exclude refunds for energy purchased in the Pacific Northwest spot market for consumption outside the geographical area."). Second, the court held that FERC should have interpreted the Puget complaint as it had interpreted another energy-crisis complaint requesting caps on bids into California's centralized energy market, as not "limiting refunds to entities that purchased energy for ultimate consumption in California." *Id.* at 32a. Third, the court emphasized that it had ruled in *Public Utilities Commission* v.

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[2] The court of appeals resolved this issue only after first concluding that FERC could not have found, on the record before it, that the CERS purchases occurred in California. Pet. App. 30a-31a. The court therefore concluded that it "must determine whether sales to CERS were outside the scope of the Pacific Northwest refund proceeding even if the legal change of ownership occurred in the Pacific Northwest." *Id.* at 31a. Petitioners do not seek review of this fact bound threshold ruling by the court of appeals. It presumably is open to FERC on remand to revisit that threshold issue.

FERC, 462 F.3d 1027, 1064 (9th Cir. 2006), that California transactions were outside the scope of that proceeding "based in substantial part on the existence of this proceeding involving the Pacific Northwest." Pet. App. 33a.

The court's reasoning does not withstand scrutiny. In construing a complaint, an agency must consider the entire context of the complaint and base its construction on each element of the complainant's theory of relief in order to determine the issues for adjudication. See *Burlington N. R.R.* v. *ICC*, 985 F.2d 589, 594 (D.C. Cir. 1993). The scope of a complaint should not be defined by what it fails expressly to exclude, nor must a complaint be interpreted on the basis of how a different complaint—brought by different complainants, involving different markets, and asserting different theories of relief—was interpreted in a different case. See *Colorado Office of Consumer Counsel*, 490 F.3d at 956. Finally, basing an interpretation of a complaint on whether a non-complaining party would have a remedy is not relevant to the task before an agency in construing a complaint's scope.

As petitioners appear to recognize, however, the proper interpretation of the complaint involved in this case is not an issue that warrants this Court's review. Instead, petitioners say (Pet. 28-32) that the decision below conflicts with decisions of other courts of appeals because the court of appeals failed to defer to the agency's reading of the complaint. But the court expressly acknowledged that it "owe[d] deference to FERC's interpretation of the scope of Puget's complaint," and it cited both *Burlington Northern*, *supra*, and *Amerada Hess Pipeline Corp.* v. *FERC*, 117 F.3d 596 (D.C. Cir. 1997), two of the cases on which petition-

ers rely in suggesting a conflict. Pet. App. 31a. Thus, the error of the court of appeals consists only in the misapplication of a correctly stated rule of law to the particular facts of this case, which is still at an interlocutory stage. That error does not warrant this Court's review.

CONCLUSION

The petition for a writ of certiorari should be denied.

Respectfully submitted.

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Supreme Court of the United States

PUGET SOUND ENERGY, INC., AVISTA CORPORATION, AVISTA ENERGY, INC., CONSTELLATION ENERGY COMMODITIES GROUP, INC., IDACORP ENERGY L.P., MORGAN STANLEY CAPITAL GROUP INC., PORTLAND GENERAL ELECTRIC COMPANY, POWEREX CORP., SEMPRA ENERGY TRADING LLC, SHELL ENERGY NORTH AMERICAN (US), L.P., AND TRANSCANADA ENERGY LTD.,

Petitioners,

v.

THE PEOPLE OF THE STATE OF CALIFORNIA EX REL. EDMUND G. BROWN JR., ATTORNEY GENERAL, THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, THE CITY OF SEATTLE, WASHINGTON, THE PORT OF SEATTLE, WASHINGTON, AND THE CITY OF TACOMA, WASHINGTON,

Respondents.

On Petition For A Writ Of Certiorari To The United States Court Of Appeals For The Ninth Circuit

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QUESTIONS PRESENTED

1. This Court ruled in *Heckler v. Chaney*, 470 U.S. 821, 838 (1985) that courts lack jurisdiction to review an agency's refusal to institute enforcement proceedings. When an agency "*does* act to enforce," however, its decision is reviewable. *Id.* at 832. The first question for review is:

Did the court of appeals lack jurisdiction under *Heckler* to review the decision of the Federal Energy Regulatory Commission ("FERC") to deny refunds to purchasers of electricity in the Pacific Northwest, where that decision was based on an administrative law judge's findings and recommendations after a contested evidentiary hearing?

2. Did the court of appeals err by ordering FERC to address evidence of market manipulation that FERC admitted into the record but failed to address in its decision?

3. After FERC interpreted an administrative complaint to exclude refunds for certain types of energy purchases, did the court of appeals err when, applying the same standard as the D.C. Circuit, the court rejected FERC's interpretation on the grounds that the face of the complaint demonstrated no intention to exclude such purchases and FERC's interpretation of the complaint was inconsistent with its prior interpretation of a closely-related complaint?

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BRIEF IN OPPOSITION

Respondents the City of Seattle, Washington ("Seattle"), the Port of Seattle, Washington ("Port"), the City of Tacoma, Washington ("Tacoma"), the People of the State of California ex rel. Edmund G. Brown Jr., Attorney General of the State of California (the "California Attorney General"), and the Public Utilities Commission of the State of California (the "CPUC") oppose the petition for a writ of certiorari to review the opinion of the Ninth Circuit Court of Appeals in this case.

INTRODUCTION

The Ninth Circuit Court of Appeals reviewed a FERC decision denying refunds for overcharges on wholesale electricity sales in the Pacific Northwest during the energy crisis of 2000-2001. The court reversed the decision on narrow fact-bound grounds and remanded it to FERC for further proceedings. The decision was correct and does not warrant review.

In *Heckler v. Chaney*, this Court held that an agency's refusal to institute enforcement proceedings is presumptively not subject to judicial review. The Ninth Circuit's decision does not conflict with *Heckler*, nor does it conflict with decisions of other circuit courts of appeals interpreting *Heckler*. FERC could have avoided judicial review by conducting whatever investigation it wished and making

whatever enforcement decision it wished, so long as it did not conduct an adjudicative proceeding. But FERC elected the latter course. After Puget Sound Energy, Inc. ("Puget") filed a complaint seeking relief from unreasonable electricity prices during the energy crisis, FERC allowed other Pacific Northwest purchasers to intervene and become parties, and then directed an administrative law judge ("ALJ") to conduct a public adjudicative proceeding to determine whether there were grounds to provide refunds for transactions in the Pacific Northwest (the "PNW Refund Proceeding"). The PNW Refund Proceeding involved discovery, the submission of extensive evidence, cross-examination, briefing, findings by an ALJ, oral arguments by the parties, and a decision by FERC to deny refunds. The court of appeals' review of this adjudicative decision did not in any way impair FERC's exercise of its separate discretionary enforcement authority.

Similarly, the Ninth Circuit's instruction that FERC address evidence of intentional market manipulation on remand did not improperly interfere with FERC's discretion to structure its own proceedings. Petitioners' argument rests on their incorrect factual assertion that FERC decided to address evidence of market manipulation and tariff violations occurring in the Pacific Northwest in separate seller-specific proceedings (the "Gaming & Partnership Proceedings"). But FERC specifically limited the Gaming & Partnership Proceedings to unlawful behavior in the

organized California markets and *excluded* the Pacific Northwest.

Nor does the court of appeals' decision conflict with the D.C. Circuit's deferential standard for reviewing agency decisions. The court of appeals rejected FERC's interpretation of the Puget complaint as excluding sales to the California Energy Resources Scheduling division of the California Department of Water Resources ("CERS") in the Pacific Northwest. The court cited with approval the D.C. Circuit's standard, and gave due deference to FERC. The court nevertheless was compelled to reject FERC's interpretation of the Puget complaint because that interpretation was inconsistent with the complaint's own words and directly contradicted FERC's interpretation of a closely-related energy crisis complaint involving sales in California markets.

Finally, the decision is interlocutory because the court of appeals remanded the case back to FERC, which may or may not ultimately award refunds.

In sum, the court of appeals applied settled law in a limited, fact-bound decision that was fully consistent with *Heckler* and in conformity with standard judicial practice in all circuit courts of appeals. The petition for certiorari should be denied.

———♦———

STATEMENT

The Federal Power Act ("FPA") provides that the business of selling electricity in interstate commerce "is affected with a public interest," and that federal regulation of such sales is "necessary in the public interest." FPA Section 201(a), 16 U.S.C. § 824(a). Rates charged for wholesale electricity by a public utility must be "just and reasonable." FPA Section 205(a), 16 U.S.C. § 824d(a). Whenever FERC, after a hearing on its own motion or in response to a complaint, finds that a rate is unjust and unreasonable, it is required to determine the just and reasonable rate and has discretion to order that refunds be paid. FPA Section 206(a) and (b), 16 U.S.C. § 824e(a) and (b). Complaints may be filed by any person, State, municipality or state commission. FPA Section 306, 16 U.S.C. § 825e. If FERC determines that a complaint has any reasonable basis, it must conduct either an internal investigation or a public hearing. FPA Sections 306, 307 and 308, 16 U.S.C. §§ 825e, 825f and 825g. Any aggrieved party may seek judicial review of an order issued by FERC. FPA Section 313, 16 U.S.C. § 825*l*.

1. In August 2000, San Diego Gas & Electric Company filed a complaint with FERC that initiated a proceeding (the "California Refund Proceeding") requesting that FERC order a cap on "prices at which sellers subject to its jurisdiction may bid energy or ancillary services into California's two large bulk-power markets – those operated by the PX and the ISO." Resp. App. 2.

In October 2000, Petitioner Puget filed a closely-related complaint with FERC, contending that "California and the Pacific Northwest are part of the substantially integrated wholesale power market of the Western Interconnection."[1] Resp. App. 37. Puget also contended that FERC would seriously disrupt and distort that integrated wholesale market if it established price caps in only one part of that market as requested by the San Diego complaint. *Id.* at 40. Accordingly, Puget requested that, if FERC decided to impose a price cap in response to the San Diego complaint, it should also impose the same or a lower price cap on wholesale energy prices in the Pacific Northwest. *Id.* at 39-41.

Contrary to Petitioners' representation that Puget "expressly disclaimed interest in refunds," Pet. 5, the Puget complaint specifically asked FERC to set a refund effective date "in accordance with Section 206 of the [FPA] . . . sixty . . . days after the date of filing of this Complaint" (the earliest possible date for obtaining refunds under the then-applicable version of FPA Section 206) if FERC decided to order refunds

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[1] "Western Interconnection," "West-wide," and "West" refer to the geographical area encompassed within the Western Electricity Coordinating Council. It extends from Canada to Mexico and includes all or portions of fourteen western United States, the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California.

"in response to this Complaint." Pet. App. 11a, Resp. App. 42, 44.[2]

Less than two months later, shortly after finding in the California Refund Proceeding that prices in the California spot markets operated by the PX and ISO were unjust and unreasonable, FERC dismissed the Puget complaint, asserting that a West-wide price cap was "impracticable." 93 FERC 61,294 at 62,019. Puget filed a request for rehearing.

2. On June 19, 2001, FERC issued an order setting price caps on spot market sales throughout the West, including the Pacific Northwest, based on its finding that "'the California market is integrated with those of other states in the [West].'" Pet. App. 12a, Resp. App 127. Contrary to its finding several months earlier when it dismissed the Puget complaint, FERC concluded that a West-wide price cap was not only practical but also necessary "to modify the existing market structure throughout the West to minimize the potential for market power abuse, and thus to protect against possible unjust and unreasonable rates." Resp. App. 61.

A few days later, claiming to be satisfied with the remedy provided by the June 19 order, Puget filed a motion to withdraw its complaint. *Id.* In response, Port, Tacoma, Seattle, and the Washington Attorney

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[2] The court of appeals specifically rejected the contention by Puget and other sellers that "Puget's complaint never requested refunds or the setting of a refund effective date." Pet. App. 25a.

General filed answers opposing the motion, explaining that a dismissal would prejudice other entities that relied on the Puget complaint. Pet. App. 12a-13a. Consistent with FERC procedure in adjudicative proceedings, FERC allowed these entities to intervene. *Id.*

3. On July 25, 2001, FERC issued an order in both the California Refund Proceeding and the PNW Refund Proceeding. With respect to the former, FERC "establish[ed] the scope of and methodology for calculating refunds related to transactions in [the California Refund Proceeding]" and "establish[ed] an evidentiary hearing proceeding in order to further develop the factual record in [the California Refund Proceeding] so that refunds may be calculated." Pet. App. 38a-39a. With respect to the latter, FERC established a separate evidentiary "proceeding before an [ALJ] to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest from December 25, 2000 through June 20, 2001, and the calculation of any refunds associated with such charges." *Id.* at 39a. FERC invited parties to the California Refund Proceeding to participate in the PNW Refund Proceeding. *Id.* at 13a, 102a-103a.

An ALJ conducted pre-hearing conferences in the PNW Refund Proceeding and issued an order on August 23, 2001 listing the issues to be tried, including whether refunds for spot market sales in the Pacific Northwest are "lawful or appropriate" and the "extent of any potential refunds." Pet. App. 114a.

After allowing the parties to engage in discovery, the ALJ conducted a three-day adjudicative hearing during which the pre-filed initial and/or rebuttal testimony of over 40 witnesses was taken and subjected to cross-examination. *Id.* at 417a-419a.

On September 24, 2001, the ALJ issued her "Recommendations and Proposed Findings." Pet. App. 111a-377a. Contrary to the Commission's prior determinations that the Pacific Northwest is a component part of a larger, single, inextricably integrated market that includes California, *id.* at 12a, the ALJ did not find the Pacific Northwest market to be connected to the California market in any significant way. The ALJ found that the Pacific Northwest market was functional and competitive and that prices were just and reasonable. *Id.* at 13a-14a. Accordingly, the ALJ recommended that refunds be denied. *Id.* at 14a. The ALJ also recommended that the Puget complaint be dismissed and that Puget be allowed to withdraw its rehearing request. *Id.* at 371a.

On December 19, 2002, while FERC was considering the findings and recommendations of the ALJ, new evidence came to light regarding Enron's manipulation of the electricity markets. Pet. App. 14a. FERC reopened the evidentiary record in the PNW Refund Proceeding to allow the parties to conduct additional discovery and submit "additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20,

2001" – a more extensive refund period than the one requested in the Puget complaint. *Id.*; Resp. App. 154. FERC also indicated that it would review the new evidence itself rather than remand for findings by the ALJ. Resp. App. 161-62. On March 3, 2003, Seattle, Port, and Tacoma submitted voluminous evidence supporting refund claims in response to this order.

On June 25, 2003, FERC adopted the ALJ's recommendation to deny refunds without addressing the new evidence submitted at FERC's own invitation. FERC rejected the ALJ's recommendation to allow Puget to withdraw its complaint because to do so would be unfair to parties seeking refunds who had "reasonably relied on the Puget complaint, which raised similar issues, as an appropriate forum for addressing their overlapping claims." Pet. App. 388a. FERC declined to make any finding as to whether wholesale market prices in the Pacific Northwest were unjust and unreasonable, instead concluding that, even if prices were unjust and unreasonable, the balance of equities weighed against ordering refunds. *Id.* at 392a-401a. Finally, FERC followed the ALJ's recommendation to exclude from the PNW Refund Proceeding transactions involving electricity purchased in the Pacific Northwest for consumption in California. *Id.* at 432a.

Respondents timely filed requests for rehearing of the June 2003 order, which FERC denied.

4. Respondents subsequently petitioned the Ninth Circuit Court of Appeals for review.[3] On August 24, 2007, the court of appeals granted the petitions in part and denied them in part. As a preliminary matter, the court rejected FERC's argument that, under *Heckler v. Chaney*, it lacked jurisdiction to review FERC's decision to deny refunds. The court of appeals recognized that, under *Heckler*, courts lack jurisdiction to review "'an agency's decision not to prosecute or enforce[,]'" but observed that, "when 'an agency *does* act to enforce, that action itself provides a focus for judicial review.'" Pet. App. 17a-18a (quoting *Heckler*, 470 U.S. at 831-32). Following *Heckler*, the court of appeals concluded that, "where FERC has made a determination to adjudicate a dispute or take[s] steps toward enforcing a violation of the law, the outcome it chooses is subject to judicial review[.]" *Id.* at 18a. The court found that FERC had taken those steps in this case by allowing interested persons to intervene, holding hearings, and taking evidence to adjudicate the refund dispute between the parties, and that FERC's ensuing decision to deny refunds was therefore reviewable. *Id.* at 18a-19a.

After rejecting the procedural challenges raised by the sellers, the court of appeals determined that

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[3] Seattle, Port, Tacoma, the California Attorney General, and the CPUC each petitioned for review of FERC's decision to deny refunds. The California Attorney General and the CPUC also petitioned for review of FERC's decision to exclude transactions involving energy consumed in California.

FERC's decision to exclude sales to CERS from the PNW Refund Proceeding based on its interpretation of the Puget complaint and FERC's failure to consider or examine the evidence submitted pursuant to its December 2002 order were arbitrary, capricious, and an abuse of discretion.

The court of appeals ruled that FERC's interpretation of the Puget complaint to exclude purchases made by CERS was inconsistent with any rational reading of the complaint and directly contradicted FERC's prior interpretation of the closely-related complaint that initiated the California Refund Proceeding.[4] Pet. App. 31a-32a.

The court of appeals also ruled that, "despite a great deal of new evidence submitted to FERC in the spring of 2003," "FERC failed to take any of it into account, relying instead on the ALJ's factual findings from September 2001, which were made prior to the Enron revelations [of market manipulation]." Pet. App. 33a-34a. In light of evidence submitted in response to FERC's December 2002 order, the court observed that "FERC must at least consider the possibility that the [PNW] spot market was not . . . functional and competitive." *Id.* at 35a.

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[4] The court of appeals also found that FERC's decision that sales to CERS did not occur in the Pacific Northwest was not supported by substantial evidence. Pet. App. 31a. Petitioners have not sought review on that basis.

The court of appeals "decline[d] to reach the merits of FERC's ultimate decision to deny refunds," and remanded to FERC to further consider its refund decision in light of the newly submitted evidence and the court's related decisions, issued subsequent to FERC's final order in this case. Pet. App. 36a.

ARGUMENT

1. There is no circuit conflict regarding the court of appeals' application of *Heckler v. Chaney*.

a. In *Heckler*, this Court granted certiorari to decide whether an agency's decision "*not to exercise* its enforcement authority . . . may be judicially reviewed." 470 U.S. at 828. Petitioners were inmates sentenced to death by lethal injection who asked the Food and Drug Administration ("FDA") to take investigative and enforcement actions under the Food, Drug & Cosmetic Act to prevent the use of certain drugs for human execution. *Id.* at 824. The FDA declined to do so, stating it would not exercise its jurisdiction to interfere with the state criminal justice system. *Id.* at 824-25. This Court determined that the FDA's decision was nonreviewable. It stressed that the exception to reviewability "remains a narrow one," *id.* at 838 (citing *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402 (1971)), but ruled that an agency's decision not to prosecute or enforce "should be presumed immune from judicial review[,]" *id.* at 832.

This Court explained that decisions not to enforce are generally unsuitable for review because "an agency decision not to enforce often involves a complicated balancing of a number of factors which are peculiarly within its expertise," such as where to allocate agency resources and whether an agency is likely to succeed in its enforcement action. *Heckler*, 470 U.S. at 831. This Court further noted that an agency's refusal to act does not implicate its coercive powers. *Id.* at 832. By the same token, it observed, "when an agency *does* act to enforce, the action itself provides a focus for judicial review, inasmuch as the agency must have exercised its power in some manner." *Id.* Finally, this Court analogized an agency's refusal to institute proceedings to a prosecutor's decision not to indict. *Id.*

In the absence of any adjudication or statutory guidelines for the agency to follow in exercising its enforcement powers, this Court concluded that the FDA's refusal to act on the inmates' request provided no basis for judicial review. *Heckler*, 470 U.S. at 837-38.

b. The court of appeals cited *Heckler* and faithfully applied it to the facts of this case. Pet. App. 17a-19a. There is, as discussed below, no circuit conflict. Petitioners simply dispute whether the court properly applied *Heckler* to the facts, an issue that does not warrant review.

Here, far from refusing to institute proceedings, or engaging only in pre-enforcement activities, FERC

adjudicated the claims before it. *See Heckler*, 470 U.S. at 832. While FERC may – and sometimes does – limit an inquiry to an investigation short of prosecution, that is not what it did here. As discussed above, FERC responded to the filing of the Puget complaint by holding a public hearing and taking evidence "to adjudicate a dispute between the parties as to whether refunds should be awarded." Pet. App. 18a-19a. FERC allowed interested parties (other Pacific Northwest purchasers and public agencies representing consumer interests) to intervene and directed the parties to participate in a public evidentiary proceeding to determine "whether there may have been unjust and unreasonable charges for" spot market sales in the Pacific Northwest.[5]

In the course of this adjudicative proceeding, the ALJ authorized discovery, received direct and/or rebuttal testimony from 40 witnesses and gave the parties the opportunity to cross-examine those witnesses. Pet. App. 417a. After the conclusion of the hearing and submission of post-hearing briefs, the ALJ issued proposed findings of fact and recommendations, and the parties were given the opportunity to file comments with FERC in response. Pet.

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[5] Indeed, under FERC's investigative regulations, "[t]here are no parties, as that term is used in adjudicative proceedings, in an investigation under this part and no person may intervene or participate as a matter of right in any investigation under this part." 18 C.F.R. § 1b.11; *see also Baltimore Gas & Elec. Co. v. FERC*, 252 F.3d 456, 458 (D.C. Cir. 2001) (according to FERC, "third parties have no right to participate in investigations").

App. 417a-418a. FERC then allowed the parties to supplement the record with additional evidence supporting refunds, including refunds for time periods not covered by the Puget complaint, and to submit evidence regarding manipulation of the energy markets by Enron and other sellers. Pet. App. 14a, 418a; Resp. App. 161-62. Finally, FERC reviewed the record, along with the ALJ's findings and recommendations, and, following oral argument before the full Commission, issued a written decision declining to order refunds. Pet. App. 379a.

Ignoring the adjudicative nature of the proceeding, Petitioners argue that FERC's decision to deny refunds is not reviewable because FERC did not "initiate a proceeding." Pet. 19-21 & n.5. This curious assertion is based on Petitioners' claim that FERC never set Puget's complaint for a hearing. *Id.* at 20 n.5. This is simply incorrect. A hearing was held, and the Commission itself recognized that the proceeding was adjudicative. *See* Pet. App. 418a n.15 (citing adjudicative statute). Indeed, in its decision following the hearing, FERC identified the PNW Refund Proceeding as the *only* proceeding in which Respondents' claims for relief could be adjudicated. FERC explicitly rejected the ALJ's recommendation that the Commission allow Puget to withdraw its complaint and dismiss the entire proceeding, stating that: "After allowing intervenors to pursue a preliminary hearing through the Puget complaint until now, it would be unfair to deny relief based on procedural issues and

leave them with no other forum to pursue their complaints." *Id.* at 388a.

FERC's November 2003 order denying Respondents' requests for rehearing further reflects its recognition that the proceeding was adjudicative under *Heckler*. The order responds at length to objections that the ALJ's accelerated procedural schedule prevented parties from fully presenting their refund case. It defends the procedures used, finding that they comported with due process on grounds that parties had the opportunity to engage in discovery, examine and cross-examine witnesses, and supplement the record following the hearing. Pet. App. 416a-419a. As this Court has repeatedly held, due process considerations arise only in adjudications, not investigative proceedings. *S.E.C. v. Jerry T. O'Brien, Inc.*, 467 U.S. 735, 742 (1984) (the Due Process Clause is not implicated in an administrative investigation) (citing *Hannah v. Larche*, 363 U.S. 420, 440-43 (1960)); *see Hannah*, 363 U.S. at 442-43 (no right to cross-examination in investigative proceedings). FERC's recognition of its due process obligations (whether or not it met them) confirms that it viewed the proceeding as adjudicative.

In sum, FERC did not merely investigate and decide not to pursue enforcement. Instead, FERC adjudicated claims for relief and rendered a decision on the merits. Section 313 of the FPA provides that such decisions are reviewable by courts of appeals. 16 U.S.C. § 825*l*. The court of appeals in this case did nothing more than engage in the normal judicial

review of an agency's adjudicative decision, as all courts of appeals regularly do. Pet. App. 19a, citing cases.[6]

c. The circuit court cases cited by Petitioners are not in conflict with the court of appeals' decision. Petitioners' observation that "[f]our circuits interpret *Heckler* to hold that agency non-enforcement decisions do not become reviewable simply because the agency has taken investigative or pre-enforcement steps to inform its decision," Pet. 13, is irrelevant because FERC did not limit itself to such steps here.

Petitioners cite cases holding that agency decisions to settle are presumptively unreviewable. Pet. 13-15 (citing *New York State Dep't of Law v. FCC*, 984 F.2d 1209, 1213-15 (D.C. Cir. 1993); *Baltimore Gas & Elec. Co. v. FERC*, 252 F.3d 456, 459-60 (D.C. Cir. 2001); *Ass'n of Irritated Residents v. EPA*, 494 F.3d 1027, 1035 (D.C. Cir. 2007)). These cases have no bearing here. This case does not involve a settlement or anything analogous to one.

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[6] In addition to the cases reviewing FERC decisions to grant or deny refunds that were cited by the court of appeals (*i.e.*, *Pub. Utils. Comm'n of Cal. v. FERC*, 462 F.3d 1027 (9th Cir. 2006); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004); and *Consol. Edison Co. of N.Y., Inc. v. FERC*, 347 F.3d 964 (D.C. Cir. 2003)), *see Westar Energy, Inc. v. FERC*, 568 F.3d 985 (D.C. Cir. 2009); *La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378 (D.C. Cir. 2008); *Keyspan-Ravenswood, LLC v. FERC*, 474 F.3d 804 (D.C. Cir. 2007); *Constellation Energy Commodities Group, Inc. v. FERC*, 457 F.3d 14 (D.C. Cir. 2006).

Petitioners also cite cases in which an agency conducted an investigation but decided not to pursue enforcement. Pet. 15-17 (citing *Greer v. Chao*, 492 F.3d 962 (8th Cir. 2007), *Sierra Club v. Larson*, 882 F.2d 128 (4th Cir. 1989), and *Sherman v. Black*, 315 F. App'x 347 (2d Cir. 2009)). These cases too are irrelevant. Petitioners misstate the unremarkable holding in each case that agency decisions to terminate investigations without further enforcement are unreviewable by asserting that the agencies in question "launched 'investigation[s]' in which complaining parties participated and were given opportunities to respond." Pet. 17. However, apart from *Greer*, in which the complaining party sought reconsideration, 492 F.3d at 963, there is no indication in any of these cases that any party participated or was given an "opportunit[y] to respond" to the investigation. Certainly none of the cases entailed an adversary proceeding of the kind FERC conducted here. To the contrary, these cases involved standard internal agency investigations that led to nonreviewable decisions declining to enforce violations alleged by the complaining parties. The agencies in those cases did not, as FERC did here, allow numerous parties to intervene, allow extensive discovery, hold formal public hearings before an ALJ, take testimony from numerous witnesses, or issue a substantive decision after the submission of post-hearing briefs.

d. Amici Law Professors ("Amici") assert that the court of appeals' opinion will cause "hopeless confusion," Amici Br. 8, tending to (1) "discourage

agencies from devoting resources to careful decisions about enforcement" for fear of exposing their decisions to judicial review; and (2) inconvenience private parties, who will lack certainty whether a given agency decision is subject to judicial review. Amici Br. 10-12, 17-18.

The court of appeals' decision will not result in either outcome. Courts have been reviewing FERC's adjudicative decisions to deny refunds for years. Fn. 6, *supra*. Amici point to no evidence that this well-established practice has discouraged agencies from making careful decisions about enforcement, or that it has harmed private parties in any way. To the contrary, judicial review serves to improve the quality of agency decisions and to prevent abuses of agency discretion.

Amici also claim that the court of appeals' decision subjects agencies to judicial review whenever they take "*any steps*" toward enforcement of the law, including "accept[ing] delivery of a petition seeking a § 206 petition," "issu[ing] a press release expressing concern about conditions in the market," or "obtain[ing] information from regulated entities." Amici Br. 8-9. The court's decision suggests no such thing; Amici take the word "steps" out of context to argue that anything an agency does is potentially subject to review.

Contrary to Amici's misreading, the court of appeals made clear in its decision that: "When an agency *has instituted* proceedings, meaningful standards exist to review what the agency has done:

'when an agency *does* act to enforce, that action itself provides a focus for judicial review, inasmuch as the agency must have exercised its power in some manner.'" Pet. App. 18a (quoting *Heckler*, 470 U.S. at 832). "Accordingly," the court of appeals stated, "where FERC has made a determination *to adjudicate a dispute or take steps toward enforcing a violation* of the law, the outcome it chooses is subject to judicial review[.]" *Id.* (emphasis added). *See also id.* at 18a-19a ("[H]ere . . . FERC has held hearings and taken evidence to adjudicate a dispute between the parties as to whether refunds should be awarded. Although the steps FERC has taken do not require FERC to find that refunds are appropriate, FERC's decision regarding the propriety of awarding refunds is reviewable by this court.").[7]

When the word "steps" is read in context, there is no doubt about the opinion's meaning or its congruity with *Heckler*. Far from "undermining" *Heckler*, Amici Br. 3, the court of appeals' opinion follows it to hold that when, as here, FERC has instituted an adjudicative proceeding rather than conduct an internal investigation, both FERC and the affected parties

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[7] Moreover, unlike *Heckler*, which applies in situations where "there is no meaningful standard against which to judge an agency's decision," *Heckler*, 470 U.S. at 830, FERC's action here was taken in the context of a Section 206 complaint, and the FPA specifically establishes the standard for FERC's review – whether rates are unjust, unreasonable, unduly discriminatory or preferential. 16 U.S.C. § 824e(a).

should expect FERC's decision in that proceeding to be subject to judicial review.[8]

Finally, Amici suggest that FERC's decision to deny refunds is nonreviewable because it is based on equitable factors. Amici Br. 8-9. But FERC's refund decisions always involve equitable and policy factors. *See, e.g., Keyspan-Ravenswood*, 474 F.3d at 812-13; *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 816 (D.C. Cir. 1998). That does not render them any less reviewable, or any less subject to reversal if lacking a rational basis. *Id.*

2. The court of appeals did not improperly interfere with FERC's discretion to structure its own administrative proceedings when it ordered FERC to consider evidence of market manipulation in the PNW Refund Proceeding.

Petitioners argue that the court of appeals' mandate to FERC to consider evidence of market manipulation on remand in the PNW Refund Proceeding, rather than in the Gaming & Partnership

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[8] FERC knows how to structure its proceedings to draw the line between an internal investigation and an adjudication. *See, e.g., PJM Interconnection, L.L.C., et al.*, 97 FERC ¶ 61,319 (2001) (FERC denied motions to intervene in investigation initiated by show cause order regarding allegations of affiliate abuse, noting that intervention not permitted as a matter of right in investigations). FERC obviously could have conducted an investigation here, but instead chose to invite interested persons to participate in an adjudicative proceeding.

Proceedings,[9] "interfered with FERC's ability to structure its own dockets." Pet. 28. This argument rests entirely on fundamental factual misstatements regarding the nature and scope of these proceedings, FERC's reasoning, and the court of appeals' determinations.

Petitioners assert that "FERC reasonably decided to investigate and remedy allegations of tariff violations in seller-specific proceedings . . . rather than in" the PNW Refund Proceeding. Pet. 27. Petitioners identify those separate proceedings as "new proceedings specifically to investigate and redress alleged market manipulation and tariff violations in both California *and the PNW*." *Id.* at 24 (emphasis added); *see also* Amici Br. 14 (referring to the "new proceedings specifically targeted at market manipulation in California and the Pacific Northwest").

Petitioners and Amici are incorrect. FERC specifically limited the scope of the Gaming & Partnership Proceedings to examination of "gaming and/or anomalous market behavior in violation of the California Independent System Operator Corporation's (ISO) and California Power Exchange's (PX) tariffs."[10]

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[9] The Gaming & Partnership Proceedings were initiated by two FERC orders issued on the same day that FERC terminated the PNW Refund Proceeding: *Am. Elec. Power Serv. Corp.*, 103 FERC ¶ 61,345 (2003) and *Enron Power Mktg., Inc.*, 103 FERC ¶ 61,346 (2003). *See* Pet. 24.

[10] 103 FERC at 62,328 (P1); *see also* 62,328 (P2) 62,341 (P70, P71), 62,342 (ordering paragraph (A)), 62,348 (P2, P3),

(Continued on following page)

In fact, when Port requested on rehearing that FERC examine evidence of manipulation in the Pacific Northwest in the Gaming & Partnership Proceedings, FERC *refused*.[11]

Accordingly, FERC's decision to exclude "gaming practices that manipulated . . . the Pacific Northwest region," *see* fn. 11, *supra*, directly contradicts Petitioners' assertion that FERC "reasonably decided" to investigate tariff violations and market manipulation evidence in the Pacific Northwest in the separate Gaming & Partnership Proceedings.

In addition, FERC's orders initiating the Gaming & Partnership Proceedings never indicated that these proceedings were created for the purpose of addressing the new manipulation evidence submitted in the PNW Refund Proceeding. Likewise, there is no basis in the record of the PNW Refund Proceeding for

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62,351 (P12), 62,357 (P45, P46), and 62,358 (ordering paragraph (B)).

[11] *Am. Elec. Power Serv. Corp., "Order Denying Rehearing,"* 106 FERC ¶ 61,020 at 61,061 (2004) ("Port of Seattle argues that the Partnership Gaming proceeding should have included a review of potential gaming practices that manipulated all of the Western Electricity Coordinating Council (WECC) electricity market, including the Pacific Northwest region. . . . We will deny rehearing; we will not broaden the scope of these proceedings."). FERC later permitted evidence involving Pacific Northwest manipulation in certain proceedings involving Enron, but otherwise maintained its approach to excluding from all other Gaming & Partnership Proceedings review of potential gaming practices in the Pacific Northwest, including those involving the Petitioners here.

Petitioners' assertion that FERC's rationale for declining to address market manipulation therein was that these issues would be addressed in the Gaming & Partnership Proceedings. FERC itself did not articulate any such rationale at the time.[12]

Petitioners also state incorrectly that the court of appeals "recognized that 'FERC already [was] addressing market manipulation in separate proceedings focusing on misconduct[.]'" Pet. 25 (citing Pet. App. 35a-36a). To the contrary, the court of appeals held that FERC "fail[ed] to rely on this reasoning below, *see Laclede Gas Co. [v. FERC]*, 997 F.2d [936,] 945 [D.C. Cir. 1993] (FERC order 'must stand or fall on the grounds articulated by the agency in that order')[.]" Pet. App. 35a.

Finally, Petitioners mischaracterize the court of appeals' decision by claiming that "the court did not review the reasons FERC gave" for denying refunds and "made no effort to explain how allegations of market manipulation, if proved, could alter FERC's balancing of equitable factors." Pet. 25. In fact, the court of appeals carefully explained that FERC's failure to consider and address relevant evidence of

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[12] Indeed, FERC had opportunities in both its November 10, 2003 and February 9, 2004 orders denying rehearing (*see* Pet. App. 409a-447a and 448a-453a), to make the alleged connection between the June 25, 2003 Gaming & Partnership Proceedings orders and the order terminating the PNW Refund Proceeding, but it did not do so. Rather, FERC first asserted this connection in its 2005 brief to the Ninth Circuit.

market manipulation (which conflicted with the ALJ's findings of a lawful, competitive and functional market in the Pacific Northwest) was arbitrary and capricious. Pet. App. 33a-36a.[13]

3. The court of appeals gave due deference to FERC's interpretation of the Puget complaint; its rejection of that interpretation is consistent with D.C. Circuit precedent and no circuit conflict exists.

a. The court of appeals found that nothing in the Puget complaint supported FERC's interpretation that CERS' purchases in the Pacific Northwest for ultimate consumption in California were outside the scope of the complaint, that FERC's interpretation directly contradicted its interpretation of a closely-related complaint, and that FERC's interpretation was therefore "arbitrary, capricious, and an abuse of discretion." Pet. App. 31a.

Petitioners argue that the decision creates a conflict with the D.C. Circuit's standard for deference to agency rulings in *Burlington Northern R.R. Co. v. ICC*, 985 F.2d 589, 594-95 (D.C. Cir. 1993), *Amerada Hess Pipeline Corp. v. FERC*, 117 F.3d 596, 604 (D.C. Cir. 1997) and related cases. Citing these cases, Petitioners argue that the D.C. Circuit "consistently defers to agencies' constructions of parties' pleadings, particularly when the pleading falls in an area in

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[13] In light of these facts, the cases cited by Petitioners for the proposition that an agency may address issues in separate proceedings are irrelevant.

which 'the Commission has greater technical expertise . . . than does the [c]ourt,'" but the court of appeals failed to do so here because it "declined to read Puget's complaint in its proper context," and rejected FERC's interpretation based "solely on two sentences from the complaint." Pet. 29-31.

Petitioners are incorrect. There is no circuit conflict. Relying on the very same D.C. Circuit precedents cited by Petitioners, the court of appeals expressly acknowledged that "we owe deference to FERC's interpretation of the scope of Puget's complaint." Pet. App. 31a.

Contrary to Petitioners' argument, the court of appeals' decision makes clear that the court did in fact search for a basis to defer to FERC's interpretation of the complaint read in its overall context but was forced to conclude that, "[o]n its face, Puget's complaint provides no indication of an intent to exclude refunds for energy purchased in the Pacific Northwest spot market for consumption outside the geographical area." Pet. App. 31a. Petitioners cannot plausibly claim that the court of appeals' reliance on the actual words of the complaint somehow ignored the complaint's overall context. As the decision clearly shows, the court of appeals took into consideration the context of the complaint in some detail, going so far as to include FERC's contradictory interpretation of the closely-related price-cap complaint filed in the California Refund Proceeding. There, FERC construed the scope of the complaint to include transactions in the California markets regardless of where

the energy was consumed. Pet. App. 32a. Unhappily for Petitioners, the court of appeals, again expressing its agreement with the D.C. Circuit, relied on *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 815-16 (D.C. Cir. 1998) in concluding that "[w]here an agency treats similar situations differently without reasoned explanation, its decision will be vacated as arbitrary and capricious." Pet. App. 32a. *See also Nat'l Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1571 (D.C. Cir. 1987) ("[i]f the agency's interpretation of a contract has vacillated, deference might give the agency license to act arbitrarily by making inconsistent decisions without justification," making deference in that instance "inappropriate").

Deference does not mean complete abdication of judicial review. The D.C. Circuit standard applied by the court of appeals recognizes that courts cannot blindly defer to agency decisions that lack a rational basis. As the D.C. Circuit stated in *Amerada Hess*, cited by both Petitioners and the court of appeals, "deference . . . does not mean abdication of careful and thorough judicial review. . . . We will not accept FERC's interpretation . . . unless it is 'amply supported, both factually and legally.'" *Amerada Hess*, 117 F.3d at 604 (citations omitted). Here, after conducting the "careful and thorough" review endorsed by the D.C. Circuit in *Amerada Hess*, the court of appeals was compelled to reverse FERC's decision, just as the D.C. Circuit has done in similar circumstances. *See, e.g., Idaho Power Co. v. FERC*, 312 F.3d 454, 461 (D.C. Cir. 2002) (recognizing deference due to FERC's

interpretation of ambiguous tariff language but vacating FERC's decision because FERC's interpretation of the tariff was contrary to prior interpretations and "nonsensical"); *Tesoro Alaska Petroleum Co. v. FERC*, 234 F.3d 1286, 1289-95 (D.C. Cir. 2000) (recognizing that deference due to FERC decision dismissing complaints on summary disposition "does not [ ] mean passive acceptance of irrational or unexplained decision making" and reversing, finding FERC's decision "unconvincing" and lacking a reasoned explanation).

The court of appeals has done nothing more here than follow long-established principles of appropriate judicial review. The claimed circuit conflict is illusory.

b. Petitioners also claim that the court of appeals' failure to give due deference to FERC's interpretation of the Puget complaint undercuts the rule against retroactive ratemaking. Pet. 32. The rule against retroactive ratemaking flows from Section 206 of the FPA and requires that rates may be revised by FERC only after application by the seller, or after a complaint has been filed against the seller, thus providing the seller notice that a transaction may be subject to refund. *Id.* at 33. The court of appeals did not disturb this concept. The court merely held, correctly, that the Puget complaint provided clear notice to sellers "that they may be liable for refunds for sales of energy in those markets, regardless of where the energy would be consumed." Pet. App. 32a.

4. Finally, the limited holding of the decision below and the interlocutory posture of the case provide additional reasons for denying further review.

The court of appeals declined to reach the merits of the refund dispute and remanded to the Commission to conduct further proceedings, including evidentiary hearings as needed, in light of intervening case law. This Court grants review of an interlocutory decision only in extraordinary circumstances, *American Construction Co. v. Jacksonville, Topeka & K.W.R. Co.*, 148 U.S. 372, 384 (1893), and avoids doing so when it will induce inconvenience, litigation costs, and delay in determining ultimate justice, *Gillespie v. U.S. Steel Corp.*, 379 U.S. 148, 152-53 (1964). Petitioners cite no extraordinary circumstances justifying review at this juncture, because none exist. Further review at this stage will only cause delay and harm Respondents, who have been waiting for final resolution of the refund dispute for close to a decade.

CONCLUSION

For the foregoing reasons, the petition for a writ of certiorari should be denied.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	
v.	)	
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange[1]	)	**Docket No. EL00-95-000**

COMPLAINT

(Filed Aug. 2, 2000)

The design and structure of the markets conducted by the California Independent System Operator Corporation ("ISO") and the California Power Exchange Corporation ("PX") are fundamentally flawed and inherently incapable of producing workable competition to protect the interest of consumers. Therefore, pursuant to Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, San

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[1] As described more fully below, this complaint seeks amendment to the market-based rate schedules of all sellers into the markets for energy and ancillary services conducted by the California Independent System Operator and the California Power Exchange. Listing of all such sellers would be impracticable. Service of this complaint is described in footnote 22 below.

Diego Gas & Electric Company ("SDG&E") petitions the Commission for an emergency order capping at $250 per MWh the prices at which sellers subject to its jurisdiction may bid energy or ancillary services into California's two large bulk-power markets – those operated by the PX and the ISO.

The prices that now prevail in those markets do not reflect legitimate forces of supply and demand and, of themselves, belie any suggestion that the markets are workably competitive under peak demand conditions. To protect consumers in San Diego and elsewhere in California from these market failures, the Commission must intervene now.

I. INTRODUCTION AND SUMMARY

Since the beginning of June, wholesale electricity prices in California have shot up to levels that exceed, often by a multiple of three or four, prices seen at comparable load levels in prior years. The increase in prices has far outpaced the increase in fuel prices and greatly exceeds the cost of producing electricity. Quite simply, California wholesale markets are, particularly at high demand levels, dysfunctional, allowing sellers to exact prices considerably above levels that would prevail in open competition, where the demand side of the equation could participate in the market.

The impact of elevated wholesale prices has been felt statewide, as evidenced by the July 27 letter of Governor Davis to Chairman Hoecker attached as Appendix A. That impact has been particularly severe

in the San Diego area, where retail prices have been uncapped since June 1999.

Restructuring in California has, from the outset, followed a path markedly different from that followed elsewhere. The California structure is characterized, among other things, by separate responsibility for forward markets on the one hand and for real-time markets and transmission service on the other; by an imprecise zonal pricing system; and by retail rate caps that (outside the San Diego area) effectively prevent consumers from taking steps to curtail electric demand when prices are high. Operating within this structure, the ISO has increasingly resorted to inefficient and costly patchwork devices to maintain system reliability.

The Commission has made clear, with growing emphasis, that fundamental reform is needed. To date, the ISO has been less than fully responsive.

Sorting out issues of market design and structure will take time: certainly months, perhaps more. Consumers in California cannot wait that long. Nor can the ISO solve the immediate problem itself. Yesterday the ISO lowered the maximum price that it will pay for imbalance energy and ancillary services to $250 per MWh, but that cap does not apply to the larger PX markets. This Commission is charged with assuring that wholesale prices charged by jurisdictional sellers are just and reasonable. It must step in immediately to do so.

The only way that the Commission can rein in prices in bid-based markets such as those of the PX and ISO is to limit what sellers can bid. Specifically, the Commission should condition existing and future market-based rate authorizations to provide that the holder of the authorization may not submit bids to sell energy or ancillary services to or through the PX or ISO for more than $250 per MWh. That cap should remain in place while overhaul of the California markets proceeds, and until those markets are workably competitive.

II. BACKGROUND

SDG&E is a California corporation with its principal place of business at 8330 Century Park Court, San Diego, California 92123. SDG&E provides electric service to some 1.2 million customers in San Diego and Orange Counties, California.

The restructured California market began operation on April 1, 1998. Consistent with the orders of this Commission and the California Public Utilities Commission ("CPUC"), as well as state statute, the three large investor-owned utilities, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("Edison"), and SDG&E transferred operational control of their respective transmission systems to the ISO, and began purchasing all of the energy needed to serve their retail customers through the PX. Each of the utilities also began providing its retail customers direct access to alternative suppliers.

and each has divested itself of all of its fossil-fueled generation in California. Each utility's retail rates were frozen by state statute for a transition period that was to continue until the utility had recovered certain stranded generation costs. SDG&E completed such recovery in June 1999, while neither PG&E nor Edison has yet done so. Thus, retail rate caps remain in place in their service territories, but not in SDG&E's. Unless remedied soon, the ISO and PX markets will produce the same adverse effects for Edison and PG&E's customers once those companies terminate the retail rate freeze.

III. CURRENT WHOLESALE PRICES IN CALIFORNIA FAR EXCEED ANY COMPETITIVE EQUILIBRIUM.

During the past two months, energy prices in the ISO-coordinated energy markets have started to behave erratically, producing prices that are three or four times the amounts for comparable time periods last year, and roughly doubling the monthly electric bills for SDG&E's customers.[2] The problem is both acute and chronic – unlike the "needle" peaks that roiled wholesale energy markets in the Midwest last year, prices in California energy markets are not retreating to their prior levels, and the difficulties

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[2] Appendix B hereto shows prices to SDG&E's residential customers, and the savings to such customers if a $250 price cap had been in effect this summer.

show no signs of abating. Significantly, the highest load on the California ISO grid this year (43,447 MW) is well below the peak level experienced during July of last year (45,574 MW). Yet, the market has routinely cleared at much higher prices during June and July of this year than during any month last year.

Appendix C hereto, comparing final PX day-ahead prices for the Southern California zone for the months of June and July during 1999 and 2000, respectively, provides a visual depiction of this marked change. During June and July of 1999, prices rarely exceeded $150/MWh even during the highest load levels. During the same period this year, prices have frequently exploded to three and four times the levels reached last year whenever load levels exceed 33,000 MW.[3]

To be sure, input fuel prices are twice the levels of last year and, as a result, even a perfectly working market would reflect some sustained price increase under these conditions. Natural gas prices at the southern California border during June and July of 1999 averaged about $2.30/MMBTU. During June and July of 2000, these prices have averaged about

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[3] Similarly in June and July 1999, the PX day-ahead price for Southern California never exceeded $250. In 2000, that price equaled or exceeded $250 167 times and $500 59 times. Appendix D shows the PX day-ahead price for each hour of June and July for each of the two years, together with the ISO-grid load for that hour.

$4.62/MMBTU. But the higher gas prices do not begin to explain the dramatically elevated prices that prevail in 2000 compared to 1999 when load levels exceed 33,000 MW. Translating the above fuel costs into delivered power prices for a typical Southern California gas-fired generating unit (10,000 BTU/kWh heat rate, volumetric gas transportation costs, fixed and variable O&M and a 65% capacity factor) results in a cost of $36/MWh in 1999, rising to $60/MWh in 2000. As the attached charts and tabular spreadsheets show, market clearing prices during June and July of 2000 have often exceeded the $60/MWh operating cost by an order of magnitude.

According to market monitoring reports, the total cost of energy charged to the California market for the month of June was nearly half of the total for all of 1999. Indeed, during one 10-day period in June, the cost charged to the market for ancillary services exceeded the total cost for all of 1999. During the entire month of June, the ISO spent $420 million to buy ancillary service capacity, whereas in June 1999 it spent just $35 million. Moreover, hour-to-hour price movements are inexplicable – capped $500/MWh imbalance energy prices are sometimes followed the next hour by $0/MWh prices. The hourly prices for ancillary services are also erratic, with lower-valued services sometimes clearing at prices that are higher than higher-valued services. In short, the design and structure problems inherent in the ISO's decentralized approach to market coordination is breaking down whenever the market is even moderately

stressed. These markets thus pose a clear threat to the economic and social well-being of California, its economy, and its citizens, especially in San Diego.

IV. BECAUSE THE DESIGN AND STRUCTURE OF THE CALIFORNIA ISO IS FUNDAMENTALLY FLAWED, A WORKABLY COMPETITIVE MARKET DOES NOT EXIST.

Restructuring of the electric industry has proceeded on the premise that competitive supply markets are both desirable and possible. It has long been recognized that the peculiar physical characteristics associated with electricity require that a structure be put in place that will establish "workably" competitive generation markets for the overall benefit of consumers. SDG&E believes in competition and believes that a workably competitive market for electricity is in the best interest of California and the nation, and will, if properly established, lead to lower prices. SDG&E has, however, understood from the beginning that the task of forming workably competitive markets is not easy and that the very best market structure and design concepts must be brought to bear to achieve the stated goals. SDG&E has stated publicly on many occasions its reservations about the structure adopted in California compared to other structures employed elsewhere in the nation.

Any weakness in the design of a market structure will quickly be exposed by market participants, even when engaged in wholly-permissible activities. This is what has happened in California. The only protection for consumers is a properly designed market that deals explicitly with the physics and externalities associated with a transmission network that is frequently congested and thus incapable of supporting all of the transactions that market participants prefer to execute.

According to the ISO, the design principles "that guided the California approach to restructuring . . . are captured most succinctly in two concepts: (1) full separation of competitive forward energy markets from monopoly transmission service, and (2) decentralized production decisions (unit commitment, dispatch, generation investment)."[4] The approach of the California ISO is unique in this regard, differing materially from the more centralized approach used by the PJM and New York ISOs, which attempts to preserve the well-known consumer benefits associated with an economically-efficient, least-cost dispatch.[5] Notwithstanding the California ISO's claims

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[4] *California ISO Congestion Management Reform Recommendation (Draft)*, July 11, 2000 at 15, hereinafter referred to as the *Reform Proposal*. The ISO report can be found at the California ISO's web site (http://www.caiso.com/clientservices/stakeholderprocesses/congestion management).

[5] The PJM and New York systems use an ISO-coordinated spot market based on a bid-based, security-constrained economic dispatch with nodal prices, financial transmission rights, and

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of having achieved a significant breakthrough in market design, the facts suggest that the California ISO – even after some 30 amendments to its tariffs – has failed to produce a market capable of supplying the electricity needs of California consumers at competitive prices.[6]

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the option of using either pool-based or physical bilateral schedules.

[6] SDG&E is not alone in concluding that wholesale markets in California are not workably competitive, at least at high load levels. The ISO Board explicitly so found in a resolution adopted on June 28, 2000. So too did Dr. Frank Wolak, Chairman of the ISO's Market Surveillance Committee ("MSC"), which is independent of ISO management. *See* Frank A. Wolak, "Recent Events in the California Electricity Industry and the Level of Price Caps on the ISO's Energy and Ancillary Service Markets" at 2. The report is available at http://www.caiso.com/docs/2000/07/06/200070615111266687.html. Defects in the markets have been catalogued by the MSC and by the PX's independent market monitoring organization in reports filed over the past two years. *See Report on Market Issues in the California Power Exchange Energy Markets*, filed in Docket Nos. ER 98-2843-001, *et al.* (Aug. 17, 1998); *Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator*, filed in Docket Nos. ER98-2843-001, *et al.* (Aug. 19, 1998); *Second Report on Market Issues in the California Power Exchange Energy Markets*, filed in Docket Nos. ER98-2843-006, *et al. (March 10, 1999)*; *Report on Redesign of Markets for Ancillary Services and Real-Time Energy*, filed in Docket Nos. ER98-2843-007, *et al.* (April 6, 1999); *Annual Report on Market Issues and Performance*, filed in Docket No. ER99-3158-000 (June 4, 1999); *MSC's Report On Redesign of California Real-Time Energy and Ancillary Services Markets*, filed in Docket Nos. ER98-2843-000, *et al.* (Oct. 18, 1999); *PX Annual Report*, filed in Docket Nos. ER 96-1663 and EC 96-19 (July 30, 1999); *Third Report on Market Issues in the California Power Exchange*

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Difficulties with implementing the California ISO's novel approach to market coordination have been visible from the beginning, but most observers suspended judgment while the ISO struggled to implement its "de-centralized" approach to market coordination.[7] But instead of settling down and showing signs of maturity, the ISO-coordinated markets have increasingly required non-market "command and control" procedures to preserve short term reliability. Because the ISO does not have effective market-based procedures to keep the system in balance and maintain reliability – such as accurate locational pricing to support market-based congestion management; a well-structured day-ahead market to coordinate efficient unit commitment and a bid-based economic dispatch of the available generators; ancillary services markets properly designed and integrated with the day-ahead and balancing energy markets; and effective tools for mitigating locational market power – the ISO has been forced to develop jury rigged" solutions to countermand the perverse incentives produced by poor market design and structure. The resulting extra-market costs from

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Energy Markets, filed in Docket Nos. ER98-28843-000, *et al.* June 7, 2000).

[7] During much of the transitional start-up period, the ISO's prices were capped at $250/MWh – a number clearly higher than the running cost of any generator serving the California market but a comfort nevertheless for the utility distribution companies responsible for serving retail consumers at a commodity rate approximating one fifth of the wholesale cap.

these non-market solutions, of course, are passed on to consumers (more precisely, the utility distribution companies like SDG&E) through higher uplift payments.

Fortunately, the Commission eventually saw fit to intervene and question these practices, declaring the ISO's congestion management system to be fundamentally flawed and in need of overhaul or replacement, a finding that effectively touches on virtually every aspect of the California approach to market design.[8] The fate of other recent proposals and initiatives by the ISO illustrates that the California experiment in de-centralized market coordination is breaking down on a number of fronts. By the time the Commission found fundamental flaws in the ISO congestion management processes, it had already rejected the ISO tariffs governing generator interconnection. The Commission determined that the ISO-adopted procedures would undermine competition and discriminate against new entrant generators.[9] Shortly thereafter, the ISO withdrew the controversial long-term-grid-planning procedures that it had filed at the Commission. Belatedly, the ISO itself has come to concede that real problems exist, but it continues to argue that failures in

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[8] *California Independent System Operator Corp.*, 90 FERC ¶61,006 (January 7, 2000).

[9] *California Independent System Operator Corp.*, 88 FERC ¶ 61,221 (September 15, 1999); *reh'g denied*, 90 FERC ¶ 61,086 (January 31, 2000).

implementation rather than errors in the original market structure and design principles are the source of most of the difficulties.[10]

In some sense, these rejected and withdrawn proposals represent progress. The ISO's lawyers no longer need vigorously defend the ISO's implementation protocols, arguing that market separation, congestion management, and zonal pricing rules are functioning well and adequately police the ability of generators to exercise market power.[11] The Commission, of course, has now concluded otherwise, and directed the ISO to overhaul or replace its congestion management system and to review its market power mitigation practices. California consumers should not be expected to pay dramatically higher prices, however, while the ISO begins to confront and remedy the market power problems inherent in its de-centralized approach to market coordination.

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[10] *Reform Proposal* at 13.

[11] *See* the January 27, 2000, Answer of the California Independent Operator Corporation to Motions to Intervene and Reply Comments, criticizing the analysis and conclusions reached by Drs. Harvey and Hogan in *Nodal and Zonal Congestion Management and the Exercise of Market Power*, which had been submitted as part of Sempra Energy's comments on the ISO's *Report to the Federal Energy Regulatory Commission: Studies Pursuant to the October 30, 1997 Order*, Docket No. ER00-703-000. *See also* Drs. Harvey and Hogan's *Further Comment* attached to Sempra Energy's February 14, 2000, Answer, rebutting the ISO's claim that its zonal pricing system does not afford additional opportunities for exercising generator market power.

SDG&E does not, of course, believe that all of the current troubles can be laid solely at the feet of the California ISO and the poorly designed and structured wholesale markets that it coordinates. There are contributing factors not within the control of the ISO or this Commission that must also be addressed before the California market will work fully as intended. For instance, California needs more supply-side resources, both generation and transmission, to serve its growing load and to relieve significant transmission constraints. According to the California Energy Commission, 3,643 MW (five projects) will be under construction by the end of 2000, and 8,295 MW (14 projects) are under siting review.[12] Regulatory delay in siting new supply-side facilities must not be allowed to undermine the ability of the markets to function reliably. Conversely, just throwing more resources into the mix will not produce efficient results for consumers if the ISO's market-coordination procedures are dysfunctional and allow prices to remain well above competitive levels.

California's vision of industry restructuring also contemplated a vibrant retail market, where energy service providers would compete to manage price and supply risks for end-use customers. SDG&E fully supports California's decision to place the supply and price risk management function in the hands of

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[12] *See* http://www.energy.ca.gov/sitingcases/projects since 1979.

merchant companies with the skills and profit motive to execute this critically important function, but the retailing part of the restructured industry has not been able to make much headway, and few residential customers have left the "default" service provided by the utility distribution companies. Under California's restructuring polices, SDG&E has become an energy "delivery" company, but it will continue until directed otherwise to provide supply service for customers that have not yet chosen a supplier, by passing through the wholesale price in the PX and ISO markets. This is fine for consumers that are comfortable riding the spot market, but the volatility associated with even a workably competitive electricity market may not be acceptable for many consumers that would prefer to have some control over the price they will be charged for electricity. In addition to the *de facto* absence of market-based risk management for residential customers, California policy makers are grappling with the current inelasticity of demand (primarily because of the rate cap shielding Edison and PG&E's customers from the spot energy prices), and the lack of widespread deployment of hourly meters to allow customers to tailor their consumption patterns to market prices.

The resource siting and retail problems discussed above are all contributing to produce the unsatisfactory results facing SDG&E's customers. But the existence of these problems must not distract the Commission's attention from the basic inadequacy of the ISO/PX system – the ISO-coordinated wholesale

markets that are subject to the Commission's exclusive jurisdiction are dysfunctional, inefficient, and incapable of producing just and reasonable rates when loads reach moderately high levels. The Commission did not design this market, but its statutory responsibilities require that it lead the effort to fix the problems. The Commission must also take immediate, interim measures to protect consumers until reforms are in place and the Commission is able to certify that the design and structure of the California wholesale markets will produce workable competition.

V. THE ON-GOING STAKEHOLDER PROCESS TO REFORM THE ISO'S CONGESTION MANAGEMENT SYSTEM AND RELATED PROCESSES IS IMPORTANT AND NECESSARY, BUT COMES TOO LATE TO PROTECT CALIFORNIA CONSUMERS.

The Commission has extended substantial deference to the California ISO's unique approach to coordinating the short-term markets and has intervened to prompt reform only when it became clear that the ISO's Board of Governors was simply unable or unwilling to confront the underlying structure and design problems that now seem apparent to all.[13] The California markets will not

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[13] Unlike the other ISO's regulated by the Commission, most (but not all) of the members that sit on the California ISO's Board of Governors represent economic interests directly

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function consistently with the public interest until consumer welfare is placed at the top of the design list.

The Commission must insist that the California ISO market-coordination function be reformed to support efficient and effective competition. The mantra usually heard stakeholders want market separation, de-centralized decision making on dispatch and unit commitment issues, and suppression of locational pricing differentials – must not be allowed to stand in the way of a full examination of the reasons why the ISO/PX markets are not workably competitive. The ISO's July 11 *Reform Proposal*, which has been circulated to market participants for comment, on the one hand acknowledges that the current market-coordination practices are not working well, but, on the other hand, extols the virtues of the current market structure and design and steadfastly refuses to propose the changes that are necessary to support workable competition. Consequently, SDG&E is not optimistic that this Commission-initiated stakeholder reform effort will produce meaningful results without additional direction from the Commission.[14]

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affected by the ISO's market-coordinating tariffs and protocols, thus making it difficult to introduce reforms that could potentially disturb the existing economic and financial order.

[14] SDG&E is concerned that the ISO's *Reform Proposal* will not produce a workably competitive market, because the proposal would: 1) introduce more uncertainty and raise costs by

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SDG&E had hoped that the ISO's *Reform Proposal* would present a straightforward and compelling analysis of how the new approach would better mitigate market power and improve the performance of the market. SDG&E is particularly disappointed that the draft report does not explain why workable solutions being used elsewhere should not also be adopted in California. The draft *Reform Proposal* has not been able to shake free from the unique constraints that were incorporated in the original California design.[15] Rather than correcting

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pushing certain unit commitment decisions further forward in time (two day-ahead "reliability" market); 2) for certain units replace the two-settlement system of financial commitments with a specific performance requirement that would raise costs; 3) undermine a market-driven approach to transmission expansion; 4) undermine load management programs; 5) inflate costs in the two-day-ahead market when intra-zonal congestion is present; 6) continue to base inter-zonal real time operating decisions on a "simplified commercial model" rather than the actual network model; 7) increase complexity and uncertainty in using FTRs to hedge congestion costs; 8) likely subsidize wheeling transactions; 9) reduce the incentive for long term bilateral transactions between load and generation within constrained regions; 10) invite zonal price suppression and price discrimination; and 11) create poor procedures for creating new zones. These concerns, as well as a number of important ambiguities that remain unresolved, have been communicated to the ISO. We are prepared to work constructively with the ISO to develop alternative proposals to address these concerns and ambiguities, but so far the ISO-facilitated stakeholder process has, in our judgment, been ineffective in examining the efficacy of the original market design and structure that the ISO says must not be "abandoned." *Reform Proposal* at 13.

[15] For instance, preservation of the so-called "market separation rule," unique to California and flawed from first

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the rules for the existing markets along the lines that have worked elsewhere, the *Reform Proposal* pursues an approach requiring introduction of new markets and even more complicated procedures than currently in place. The new markets and rules are unfamiliar and unproven, and may well produce even more opportunities for "gaming" the system, leading to generally higher prices. It is clear that these most recent proposals are a step backward away from competitive markets and a step toward more intervention by the ISO to work around the special problems that have been created by its own rules. Given that there are well-designed market systems that have worked elsewhere, the burden should now be shifted to favor those working models and against the novel and distracting contortions of the *Reform Proposal* offered by the California ISO.

VI. UNTIL WORKABLE COMPETITION IS ESTABLISHED, SUPPLY BIDS INTO THE CALIFORNIA FORWARD AND REAL-TIME MARKETS SHOULD BE CAPPED AT $250 PER MWH.

As stated above, it is clear that the markets for energy and ancillary services in California are not workably competitive, at least when overall statewide demand reaches the neighborhood of 33,000

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principles, is cited as one of the main reasons why market power and related congestion problems cannot be dealt with in the normal real-time and day-ahead markets.

MW. At such demand levels, prevalent wholesale prices – prices subject to this Commission's jurisdiction – are neither just nor reasonable: suppliers are selling electricity at prices that far exceed prices produced by competition and, of course, consumers are being required to pay these prices and enrich the generators. SDG&E remains committed to the establishment of efficient, competitive electricity markets but, in the interim, the Commission must step in. Indeed, the question is not whether it should do so but how quickly. We submit that the Commission should act with urgency.

The necessary premise upon which sellers of energy or ancillary services have been authorized, under Section 205 of the Federal Power Act, to make sales at other than cost-based rates is that such sellers lack market power *and* that the markets into which they are selling are workably competitive. If markets are not workably competitive, the Commission cannot rely upon them, as an alternative to sellers' costs, to set just and reasonable rates.[16] As

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[16] *See Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1530 (D.C. Cir.), *cert. denied sub nom. Williams Pipe Line Co. v. Farmers Union Cent. Exch. Inc.*, 469 U.S. 1034 (1984); *see also Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870-71 (D.C. Cir. 1993). The Commission requires applicants seeking market-based rate authority to show that – in combination with affiliates – they do not possess an unduly large share of the market for the relevant product in the relevant geographic area and cannot erect barriers to entry. *See Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 (1994); *Ocean Vista Power*

(Continued on following page)

shown above, the premise of workable competition does not hold true at present in the California PX and ISO energy and ancillary service markets, at least during high-load conditions.

In such circumstances, the authorization of suppliers to sell at rates exceeding cost – if continued at all – must, at the very least, be restricted. Specifically, the authorization of any seller to make sales for resale in interstate commerce at market-based rates should be conditioned to provide that, unless or until the Commission finds that bulk power markets for energy and ancillary services in California are workably competitive, such seller shall not submit a bid of more than $250 per MWh to supply energy or ancillary services into markets operated by the ISO or the PX.

SDG&E proposes a bid cap of $250 because that amount will easily exceed the variable costs of any supplier making sales into the ISO or PX markets, while still providing significant relief to consumers in high-load periods. Even the most inefficient gas-fired

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Generation, LLC, 82 FERC ¶ 61,114 (1998); *Cabrillo Power I LLC*, 86 FERC ¶ 61,180 (1999.)

The Commission has *not* required a showing that a particular market into which the applicant proposes to sell is itself workably competitive. Sellers who lack undue market share may receive prices that exceed competitive levels if they are participants in markets that, because of design flaws (or because other sellers do have unduly large shares) are not workably competitive.

generating unit should handily cover its operating costs at a $250/MWh price cap. At current natural gas prices (approximately $4.62 per MMBTU at the California border), operating costs for an inefficient gas-fired unit with a high heat rate of 20,000 BTU/kWh and a five percent capacity factor would be $147/MWh. Thus, virtually any gas-fired unit in the WSCC should be able to cover its operating costs under the $250 cap and earn some return of sunk capital costs.

As the Commission may be aware, on August 1, 2000, the ISO's Board of Governors voted to lower the ISO's purchase price cap to $250. That measure does not obviate the urgent need for Commission action. For one thing, of course, it can be reversed in the event that a relatively small number of Board members change their position – California ISO governors understandably reflect the perspectives of the particular interests they represent. More importantly, however, the ISO's price caps do not extend to transactions in the day-ahead, hour-ahead, and block forward markets conducted by the PX, which together account for the great bulk of the sales at wholesale to meet retail demand in California. In June 2000, for example, the amount of energy sold through the PX day-ahead and hour ahead energy markets together accounted for approximately four times the amount sold through the ISO real-time market. While caps on what the ISO pays for energy and ancillary services will have some effect on prices in the PX markets, that effect is indirect. Indeed, to the extent that the

ISO price caps influence PX prices, it is largely because demand will tend to migrate to the capped real-time energy market. As the ISO has emphasized, however, an increase in the portion of demand that is met in the real-time market also increases overall price volatility and makes the system less efficient to operate.[17]

Thus, a cap on the ISO's purchase price will not solve the problem at hand.[18] In contrast, a restriction on suppliers' authority to make sales at market-based rates would be directed at the proper party from a statutory perspective – the seller – and would provide broader protection against the exercise of market power and other market distortions. In short, even if the Commission could delegate to the ISO its responsibility to assure that wholesale rates charged by jurisdictional sellers are just and reasonable, such delegation would not be sufficient here.

The imposition of bid caps is not, of course, a long-term solution. The California electricity market must, as described above, be fundamentally reformed.

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[17] *See, e.g.*, the ISO's transmittal letter of January 28, 2000, in Docket No. ER00-1365-000 at 2 ("[T]he ISO most efficiently and effectively operates the ISO Controlled Grid when decisions on scheduling and commitment of resources are made through the Day-Ahead and Hour-Ahead Schedules.")

[18] The Commission has, of course, already concluded that it lacks the authority to compel the ISO to adopt a particular purchase price cap. *Morgan Stanley Capital Group Inc., v. California Independent System Operator Corp.*, Docket No., EL00-9[illegible]-000 (July 28, 2000).

The ISO's market-coordination practices must be altered to mitigate market power and improve overall efficiency; additional generation and transmission assets must be brought to bear; and the retail markets must be reformed to introduce market-based risk management and demand responsiveness. SDG&E, with its parent Sempra Energy, intends to play an active and constructive role in developing these solutions.[19] As such reforms take effect, the continued need for bid caps will need to be reassessed.[20]

VII. THIS COMPLAINT SHOULD BE PROCESSED AS QUICKLY AS POSSIBLE.

As described above, failure of bulk power markets at high-load levels is resulting, each day, in enormous transfers of wealth from captive buyers to

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[19] SDG&E welcomes the Commission's July 26, 2000, announcement that its staff will investigate the operation of bulk power markets and report its findings by November 1. California surely must be one of the primary subjects of that study. Again, however, Commission action to address the urgent circumstances described above cannot await completion of the investigation.

[20] In that regard, SDG&E hopes that conditioning the market-based pricing authority for bidders into the California PX and ISO markets will motivate suppliers to work for quick and effective market reformation so that their unfettered market-based pricing authority can be restored as promptly as possible.

generators and marketers selling through the PX and to the ISO. The need for action is genuinely urgent.

The Commission has indicated that its "Fast Track" procedures under 18 C.F.R. § 385.206(h) will not apply where the complaint seeks a change in a tariff.[21] For that reason, and because of the large number of suppliers whose market-based rate schedules are at issue, Fast Track procedures may not properly be applicable here.

On the other hand, given the urgency of the situation, time is of the essence. Accordingly, SDG&E respectfully requests that the Commission place the instant complaint on public notice as quickly as possible, and the fix time for filing answers at 15 days from the date of that notice.[22] Further, SDG&E

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[21] *Amoco Trading Corp. v. El Paso Natural Gas Co.*, 89 FERC ¶ 61, 165 (1999).

[22] SDG&E has served the instant complaint by overnight delivery or e-mail on all parties to the proceedings in which the ISO's purchase price caps have been at issue, to date, *i.e.*, Docket Nos. ER98-2843, ER99-4462, and EL00-91. It has also served the complaint on parties not included on any of those lists who are on the service list in the generic California restructuring proceedings, Docket Nos. ER96-1663 and EC96-19. Finally, SDG&E has provided this complaint in electronic form to the ISO, with a request that the ISO distribute it electronically to each entity on the ISO's list of market participants. SDG&E is also posting the complaint on its website in anticipation that its availability there will be cited in the Commission's notice of filing. SDG&E requests that, if the foregoing is not deemed to constitute substantial compliance with the requirements of Section 385.206(c), such requirements be waived.

respectfully urges the Commission to act as quickly as possible on the merits of this complaint.[23]

VIII. CONCLUSION

SDG&E respectfully requests that the Commission find that rates in excess of $250 per MWh for sales into the markets for energy and ancillary services operated by the California Independent System Operator Corporation and the California Power Exchange Corporation are unjust and unreasonable and that it condition the authorization to make sales into those markets at market-based rates accordingly. SDG&E further respectfully requests that the Commission act on this complaint at the earliest possible time.

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[23] Appendix E hereto is a notice of filing and is also submitted in diskette form, in accordance with Rule 206(b)(10). In accordance with Rule 206(b)(9), SDG&E states that none of the dispute resolution mechanisms listed therein has been used and, given the nature as well as the urgency of the issue, SDG&E does not believe that ADR under the Commission's supervision is practicable.

Respectfully submitted,

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Attorneys for San Diego Gas & Electric Company

August 2, 2000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. Complainant, v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Respondents.	)	Docket No. EL01-10-000

COMPLAINT OF PUGET SOUND ENERGY, INC.

(Filed Oct. 26, 2000)

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October 26, 2000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PUGET SOUND ENERGY, INC. **v.** **ALL JURISDICTIONAL SELLERS OF ENERGY AND/OR CAPACITY AT COMPLAINT OF PUGET WHOLESALE INTO ELECTRIC ENERGY AND/OR CAPACITY MARKETS IN THE PACIFIC NORTHWEST, INCLUDING PARTIES TO THE WESTERN SYSTEMS POWER POOL AGREEMENT**[1]	**Docket No. EL01-10-000** **COMPLAINT OF PUGET SOUND ENERGY, INC.**

[1] As discussed further below, this Complaint seeks an order affecting the market-based rate schedules of wholesale sellers of energy and/or capacity into electric energy and/or capacity markets in the Pacific Northwest, including parties to the Western Systems Power Pool Agreement. Listing all such sellers in this caption would be impracticable. PSE is serving this Complaint on all parties to the Western Systems Power Pool (as listed on the Western Systems Power Pool website, www.wspp.org) as well as providing an electronic copy of this Complaint to the Western Systems Power Pool with a request that it distribute the copy electronically to each party to the Western Systems Power Pool Agreement. PSE is also requesting that Western Systems Power Pool post the Complaint on its website. PSE requests that if its actiions as described above are not deemed to constitute substantiall compliance with the requirements of Rules 203(a)(5) and 206(c), the Commission waive such requirements in this case.

Pursuant to Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, Puget Sound Energy, Inc. ("PSE"), hereby petitions the Commission for an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy or capacity under the Western Systems Power Pool Agreement ("WSPP Agreement"), may sell capacity or energy into the Pacific Northwest's[2] wholesale power markets. PSE seeks an order that prospectively caps the prices for wholesale sales of energy or capacity into the Pacific Northwest at a level equal to the lowest cap on prices established, ordered, or permitted by the Commission for wholesale purchases in, or wholesale sales of energy or capacity to or through markets operated by, the California Independent System Operator Corporation (the "Cal ISO") or the California Power Exchange Corporation (the "Cal PX").

In support of its Complaint, PSE states the following:

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[2] As used in this Complaint, "Pacific Northwest" has the meaning set forth in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. sec. 839a(14).

I. NAME AND IDENTITY OF COMPLAINANT

1. The exact name and address of PSE is:

Puget Sound Energy, Inc.
411 – 108th Avenue, N.E.
P.O. Box 97034
Bellevue, Washington 98004-5028

All correspondence, communications, and pleadings in this proceeding should be sent to:

William A. Gaines
Vice President, Energy Supply
Puget Sound Energy, Inc.
411 – 108th Avenue NE, Suite 1500
Bellevue, Washington 98004
(425) 462-3145

It is respectfully requested that copies of all correspondence, communications, and pleadings in this proceeding be sent to:

William R. Maurer
Perkins Coie LLP
411 – 108th Avenue NE, Suite 1800
Bellevue, Washington 98004
(425) 453-6980

2. PSE is a corporation created and organized under the laws of the State of Washington, with its principal offices located in Bellevue, Washington. PSE is an electric and natural gas investor-owned utility engaged in, among other things, generating, transmitting, and marketing electric power in the West. PSE's wholesale power sales and interstate transmission of electricity are subject to the jurisdiction of

the Commission. PSE's retail service is subject to the jurisdiction of the Washington Utilities and Transportation Commission.

II. FACTS SUPPORTING THE COMPLAINT

A. Background

3. PSE sells power at market-based rates into, and buys power at market-based rates from, markets operated or directly affected by the Cal ISO and the Cal PX. For example, PSE makes sales at market-based rates into, and buys power at market-based rates from, the markets in the Pacific Northwest, which are directly affected by the Cal ISO and the Cal PX. PSE makes such power sales pursuant to or under authority of its market-based power sales rate schedule, which the Commission accepted for filing in *Puget Sound Energy, Inc.*, 86 F.E.R.C. ¶ 61,088 (1999).

3. PSE is a party to the WSPP Agreement. The WSPP Agreement has more than 220 parties, including over 97 power marketers, 53 investor-owned utilities (plus subsidiaries), 74 public entities, and one independent power producer. The WSPP Agreement sets forth terms under which parties enter into transactions to purchase and sell energy and capacity at rates that are often market-based rates. *See* Service Schedule C of the WSPP Agreement, WSPP's Rate Schedule FERC No. 6. Thousands of energy and capacity transactions take place each month by entities subject to the Commission's jurisdiction within

and between, among other places, California and the Pacific Northwest.

5. On August 2, 2000, San Diego Gas & Electric Company ("SDG&E") filed a Complaint (the "SDG&E Complaint") in Docket No. ELOO-95-000. The SDG&E Complaint alleged, among other things, that the "design and structure of the markets conducted by the [Cal ISO] and the [Cal PX] are fundamentally flawed and inherently incapable of producing workable competition to protect the interests of consumers." SDG&E Complaint at 1. The SDG&E Complaint called upon the Commission to take immediate action to limit bids into the Cal ISO and the Cal PX in an effort to stabilize prices for energy and ancillary services at the wholesale level.

6. In its Complaint, SDG&E sought an order "capping at $250 per MWh the prices at which sellers subject to [the Commission's] jurisdiction may bid energy or ancillary services into California's two large bulk-power markets – those operated by the PX and the ISO." SDG&E Complaint at 1. SDG&E's Complaint sought relief against all entities subject to this Commission's jurisdiction for whom the Commission has approved the sale of power at market-based rates.

7. The Commission has declined to institute the relief requested by SDG&E. Instead, the Commission has instituted, pursuant to section 206 of the Federal Power Act, a formal investigation to examine "the justness and reasonableness of the rates and charges

of public utilities that sell energy and ancillary services to or through the California ISO and PX, and to also investigate whether the tariffs and institutional structures and bylaws of the California ISO and PX are adversely affecting the efficient operation of competitive wholesale electric power markets in California and need to be modified." *Order Initiating Hearing Proceedings to Investigate Justness and Reasonableness of Rates of Public Utility Sellers in California ISO and PX Markets and to Investigate ISO and PX Tariffs, Contracts, Institutional Structures and Bylaws; and Providing Further Guidance to California Entities,* 92 F.E.R.C. ¶ 61,172, at 61,603 (Aug. 23, 2000).

8. Moreover, as noted by SDG&E in its Complaint, the Commission has permitted the Cal ISO to institute a price cap on its purchases of imbalance energy and ancillary services. In the order resulting from the SDG&E Complaint, the Commission described the Cal ISO purchase price cap:

> Although we have concluded that immediate seller price caps have not been justified based on the existing record, we have not disturbed the actions taken by the California ISO, in its discretion as a purchaser of imbalance energy and ancillary services, to set its purchase price cap at $250/MWh. This action addresses SDG&E's concern that pricing volatility be mitigated. While the ISO's authority to implement this cap expires in November 2000, the ISO has recently stated that it will make a timely

> filing with the Commission to extend its authority. *In addition, while only the ISO's markets are directly affected by its recent action, the ISO purchase price caps currently permitted by the Commission will serve to discipline prices in both the ISO and PX.* We disagree with SDG&E that the effect of the maximum purchase price that the ISO will pay for energy and ancillary services on prices in the PX market is only indirect.

Order Initiating Hearing, 92 F.E.R.C. at 61,606 (emphasis added); *see also Morgan Stanley Capital Group, Inc. v. Cal. Indep. Sys. Operator Corp.*, 92 F.E.R.C. ¶ 61,112 (July 28, 2000). Thus, the Commission has concluded that the existing Cal ISO purchase price cap "effectively disciplines prices in the PX markets." *Order Initiating Hearing*, 92 F.E.R.C. at 61,606. Any price cap on sales into the Cal PX or the Cal ISO would therefore expand the effect of an already existing price cap that the Commission has determined is affecting the Cal ISO and Cal PX markets.

9. On October 6, 2000, the California Municipal Utilities Association (the "Cal Munis") filed a Complaint, Request to Institute Cost-Based Rates and Motion to Consolidate (the "Cal Muni Request"). The Cal Munis sought an order from the Commission requiring "all jurisdictional sellers into the California ISO and PX markets to tender cost-based filings." Cal Muni Request at 27. The effect of such cost-based filings would be to establish a price cap on jurisdictional sales into those markets equal to the cost of service. In seeking such cost-based rates, the Cal Munis

argued that "California consumers are experiencing unprecedented, high, sustained wholesale power prices. Further, there is no end in sight, because needed investment in generation and transmission is years away." Cal Muni Request at 2. The Cal Munis also seek to consolidate their Request (Docket No. EL01-1-000) with, among other proceedings, the SDG&E docket (EL00-95-000) and the Commission's Section 206 investigation into pricing issues (EL00-98-000).

10. On October 16, 2000, Pacific Gas & Electric Company, the Southern California Edison Company, and the Utility Reform Network (the "Joint Movants") filed with the Commission a Joint Motion for Emergency Relief and Further Proceedings (the "Joint Motion"). The Joint Motion requests the Commission to, among other things, immediately impose a (interim) $100/MWh cap to apply to energy, ancillary services, and out-of-market dispatch calls in the Cal ISO and the Cal PX day-ahead, hour-ahead, day-of, and real-time markets. Joint Motion at 11. The Joint Movants allege that the "failure of California's wholesale electricity markets to produce just and reasonable prices has imposed enormous costs on the citizens and businesses of California and threatens the economic health of the entire State." Joint Motion at 3.

B. The California and Pacific Northwest Markets Are Part of the Substantially Integrated Market in the Western United States

11. California and the Pacific Northwest are part of the substantially integrated wholesale power market of the Western Interconnection, a large and complex bulk electric market serving customers throughout the Western United States, Canada, and a part of Mexico. See Prepared Testimony of Chairman James J. Hoecker, Federal Energy Regulatory Commission, before the Subcommittee on Energy Research, Development, Production and Regulation, Committee on Energy and Natural Resources, United States Senate, at p. 6 (Oct. 5, 2000) (hereinafter, "Testimony"). The Western Interconnection comprises the area in which members of the Western Systems Coordinating Council operate synchronously connected transmission systems. The Western Interconnection is one of three major interconnections in the United States and operates largely independently from the other two. The market conditions in California influence market conditions in the Pacific Northwest. *See* Testimony at 9 ("Given the highly integrated nature of the Western electrical systems, it is fair to ask the extent to which circumstances in California this summer affected wholesale prices in the Northwest."). Attachment A to this Complaint[3]

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[3] Appendix A is Attachment D to the Prepared Testimony of Stephen R. Oliver, Vice President, Bulk Marketing and

(Continued on following page)

shows historical On-Peak Spot Prices from January 1996 to September 2000. Attachment A includes, among other indices, the index of California electricity prices for the Cal PX and the Dow Jones Mid C Index[4] for the period from May 1998 to January 2000 and demonstrates a high degree of correlation between these two indices.

12. Similarly, the Prepared Testimony of BPA's Vice President, Bulk Marketing and Transmission Services, Power Business Line, before the same Subcommittee stated:

> The Pacific Northwest and California have always been significant trading partners. The two markets are connected by 7,900 MW of electric transmission interties. With open access to transmission systems, *the west coast market typically acts as one large marketplace, and Pacific Northwest electricity prices track closely with the prices in California.* . . . Therefore, the Pacific Northwest is significantly influenced by the market structure in California.

Transmission Services, Power Business Line, Bonneville Power Administration, United States Department of Energy, before the Senate Energy and Natural Resources Subcommittee and Energy Research, Development, Production and Regulation, Hearing on Northwest Energy Prices (Oct. 5, 2000).

[4] The Dow Jones Mid C Index is the weighted average price of electricity traded at Mid-Columbia, a primary trading hub, for electricity in the Pacific Northwest.

Prepared Testimony of Stephen R. Oliver, Vice President, Bulk Marketing and Transmission Services, Power Business Line, Bonneville Power Administration, United States Department of Energy, before the Senate Energy and Natural Resources Subcommittee on Energy Research, Development, Production and Regulation, Hearing on Northwest Electricity Prices, at 4-5 (October 5, 2000) (emphasis added).

13. Within the Western Interconnection, the Pacific Northwest and California are interconnected by the California-Oregon Intertie (the "COI"). This interconnection consists of several large transmission lines. Reflecting seasonal diversity in electrical load on the West Coast (i.e., high summertime loads in California due to air conditioning and high wintertime loads in the Pacific Northwest due to heating loads), power predominantly flows in seasonal directions on the COI, south in the summer and north in the winter. *See* Testimony at 6 ("During summer, when demand is high in California and water is typically available, the Northwest usually exports substantial power to California. At other times, California may export power to the Northwest.").

III. THE COMMISSION SHOULD IMPOSE A CAP IN THE PACIFIC NORTHWEST IDENTICAL TO THAT IN CALIFORNIA

14. As noted above, SDG&E, the Joint Movants, and others are seeking price caps for bids into the Cal ISO and Cal PX markets as low as (i) $100 per MWh

or (ii) the cost of service. Any price caps would, if granted, directly impact the Pacific Northwest. *See* Testimony at 9-10 ("One can expect . . . that a seller of electricity that has the option of selling its power in multiple markets likely will choose to sell in the market that offers the highest price. I do not therefore discount the possibility that prices in California may have influenced the prices asked to supply electricity to the Northwest or other Western markets.").[5]

15. Price caps of the kind requested for sales to the Cal PX and Cal ISO and those instituted by the Cal ISO for purchases are – *absent equivalent price caps on wholesale sales of energy and capacity into the Pacific Northwest* – fundamentally unfair to Pacific Northwest public utilities such as PSE and are antithetical to the development of a fair competitive wholesale power market in the Western Interconnection. Uneven application of price caps upsets the balance of purchase and sale market prices between California and the Pacific Northwest and violates Section 206 of the Federal Power Act because such uneven application is unjust, unreasonable, and unduly discriminatory or preferential. In short, it is unfair and unduly discriminatory to protect wholesale purchasers in California with a price cap and yet deny similar protection to wholesale purchasers in another part of essentially the same market, i.e., the

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[5] As noted above, the Commission has already concluded that the Cal ISO purchase price cap of $250/MWh is "disciplining" the prices in both the Cal ISO and Cal PX.

Pacific Northwest. The effect of such disparate treatment is to expose wholesale purchasers such as PSE in the Pacific Northwest to uncapped prices when they need power (e.g., to meet winter demand) and yet hobble their ability to offset the costs of such purchases with uncapped prices when they have surplus power (e.g., due to favorable hydro-electric generation conditions) for sale to California.[6]

16. Fundamental fairness and the desirability of avoiding unnecessary market distortions within the substantially integrated California and Pacific Northwest market dictate that the Commission institute a price cap for wholesale sales of energy and capacity into the Pacific Northwest that is equal to the lowest cap on prices established, ordered, or permitted by the Commission for wholesale purchases by the Cal ISO or CAL PX on wholesale sales of energy or capacity to California (whether to or through the Cal ISO or Cal PX or otherwise).

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[6] Given the substantial integration of the wholesale power market in California and the Pacific Northwest, it would be counterproductive for the Commission to impose or permit price caps on wholesale power sales or purchases into the Cal ISO or Cal PX without also establishing an equivalent price cap on wholesale power sales into the Pacific Northwest. This is because any price cap in California will tend to be ineffective insofar as it creates an incentive to export wholesale power out of California.

IV. OTHER MATTERS

17. *Refund Effective Date* (FPA Section 206(b)). The relief sought by PSE in this Complaint is prospective only, and PSE requests that any refunds ordered by the Commission reflect the prospective nature of the relief sought. If and to the extent any refund is called for in response to PSE's petition, PSE respectfully requests that the refund effective date be set, in accordance with Section 206 of the Federal Power Act (16 U.S.C. § 824e(b)), sixty (60) days after the date of filing of this Complaint.[7]

18. *Relevant Docket Numbers* (Rule 203(a)(1)). The Docket Numbers of proceedings relevant to this Complaint are EL01-1-000; EL00-95-000; EL00-98-000; EL00-104-000; and EL00-107-000.

19. *Name and address of each person against whom the complaint and petition is directed; Service of Complaint* (Rules 203(a)(5) and 206(c)). As noted above in footnote 1, PSE has served via first-class mail each party to the WSPP Agreement, as listed on

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[7] In addition, it would be unfair and arbitrary for the Commission to set a refund effective date for any Pacific Northwest utility in any proceeding before the Commission prior to the date requested by PSE herein because of the operation of the seasonal flow of power between California and the Pacific Northwest. A refund effective date prior to the date sought by PSE herein would harm Pacific Northwest consumers by exacerbating the differences in seasonal prices between the Cal ISO and Cal PX markets subject to a cap and the uncapped Pacific Northwest market.

the WSPP website, www.wspp.org. PSE has also electronically transmitted the Complaint to WSPP for posting on its website and requested that WSPP forward the Complaint electronically to each party to the WSPP Agreement. PSE requests that to the extent its actions as described above are not deemed to constitute substantial compliance with the requirements of Rules 203(a)(5) and 206(c), such requirements be waived.

20. *Dispute resolution* (Rule 206(b)(9)). PSE states that none of the dispute resolution mechanisms listed in Rule 206(b)(9) has been used and, given the nature as well as the urgency of the issues raised in this Complaint, PSE does not believe that alternate dispute resolution under the Commission's supervision is practicable.

21. *Notice of Complaint* (Rule 206(b)(10)). Attached to the Complaint and included herewith on a diskette is a Notice of Complaint suitable for publication in the Federal Register.

22. If and to the extent applicable, the remaining requirements set forth for Complaints in the Commission's Rules are contained in the body of the Complaint.

V. CONCLUSION

PSE respectfully requests that the Commission enter an order prospectively capping the prices at which sellers subject to the Commission's jurisdiction

may sell energy and/or capacity at wholesale into Pacific Northwest markets at a level that is equal to the lower of any purchase price cap instituted by the Cal ISO or the Cal PX and any sales price cap (whether as a cap on market prices or as a cost-of-service requirement) instituted by the Commission for sales into the California wholesale market, including the Cal ISO and the Cal PX. PSE also requests that, to the extent any refund is called for in response to this Complaint, the Commission set the refund effective date sixty (60) days after the filing of this Complaint.

Dated the 26th day of October, 2000.

Respectfully submitted,

PERKINS COIE LLP

By /s/ Steve Marshall

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Attorneys for Puget
Sound Energy, Inc.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served in the manner stated in footnote 1 of this pleading.

Dated at Bellevue, Washington, this 26th day of October, 2000.

/s/ William R. Maurer
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95 FERC ¶ 61,418

UNITED STATES OF AMERICA
FEDERAL ENERGY
REGULATORY COMMISSION

Before Commissioners:
Curt Hebert, Jr., Chairman;
William L. Massey, Linda Breathitt,
Pat Wood III, and Nora Mead Brownell.

San Diego Gas & Electric Company,
Complainant,

v. Docket No. EL00-95-031

Sellers of Energy and Ancillary
Service Into Markets Operated
by the California Independent
System Operator Corporation
and the California Power Exchange,
Respondents.

Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-030 EL00-98-033
California Independent System Operator Corporation	Docket Nos. RT01-85-000 RT01-85-001
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-000 EL01-68-001

ORDER ON REHEARING OF MONITORING AND MITIGATION PLAN FOR THE CALIFORNIA WHOLESALE ELECTRIC MARKETS, ESTABLISHING WEST-WIDE MITIGATION, AND ESTABLISHING SETTLEMENT CONFERENCE

(Issued June 19, 2001)

Introduction and Summary

On April 26, 2001, the Commission issued an order (April 26 Order)[1] establishing new price mitigation for sales in the California Independent System Operators (ISO) ancillary services and imbalance energy markets (spot markets).[2] The April 26 Order also instituted an investigation under section 206 of the Federal Power Act (FPA) into the reasonableness of the rates for wholesale sales in the spot markets[3] in the Western Systems Coordinating Council

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[1] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,115 (2001). On May 25, 2001, the Commission issued an order providing clarification and preliminary guidance on the implementation of the mitigation plan. 95 FERC ¶ 61,275 (2001).

[2] The price mitigation established in the April 26 Order replaced the price mitigation previously in effect for such sales, and is an outgrowth of a Commission investigation under section 206 of the Federal Power Act (FPA) of the reasonableness of rates for public utility sales through the markets operated by the ISO and the California Power Exchange (PX).

[3] As used throughout this document, the terms "spot markets" or "spot market sales" means sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

(WSCC).[4] In so doing, we were mindful that the West is a single market which is at once inextricably interrelated, yet characterized by important differences. Fundamental in this regard is that the California spot markets are presently administered largely through the ISO's centralized clearinghouse, which operates a single price auction, while sales in the rest of the West are consummated on an individual bilateral contract basis and not through a centralized clearinghouse.

We have received and carefully considered many comments on how to change or improve our price mitigation in California and on whether and how to initiate price mitigation in the rest of the WSCC. Today, we will prescribe price mitigation for spot markets throughout the West which will guide the WSCC's energy markets through the difficult process of self-correction. In so doing, we seek to intervene in markets in as limited a manner as possible consistent with our responsibilities to ensure just and reasonable rates under the FPA, to rely on market principles wherever we can, and to balance carefully the need for price relief against the need for price signals to attract critical supply entry.

Today's order is one of a series of mitigation directives that began with our underlying order,

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[4] References throughout this document to the WSCC are intended to refer only to the United States portion of the WSCC.

issued December 15, 2000,[5] to correct dysfunctions in the wholesale power markets operated by the ISO and PX. Specifically, the elimination of the mandatory buy-sell requirement and the elimination of the PX rate schedule have helped to turn the tide in eliminating California investor-owned utilities' chronic reliance on spot markets. The effects of the price mitigation directed by our December 15 Order and the actions of the State of California in moving to longer-term contracts and conservation efforts have had a significant dampening effect on prices. As a result, California investor-owned utilities no longer rely on spot markets for meeting the entirety of the needs of the electric customers they serve. California now forecasts that it will only rely on the spot markets this summer for about 20% of its on-peak energy requirements, as compared to 100% prior to the December 15 Order.[6] In fact, in certain hours, the ISO data show no purchases whatsoever in its imbalance energy market. Because this market is the closest in time to when load must be met, it can exhibit the highest prices in times of shortage.

The reduction of the size of the ISO's spot market to levels more reflective of appropriate risk

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[5] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000) (December 15 Order).

[6] Update of California Department of Water Resources Power Purchase Contract Efforts, California Department of Water Resources (May 31, 2001).

management was, and remains, the cornerstone of our price mitigation. The reduction of the size of California's spot market in conjunction with the mitigation plan adopted in our April 26 Order, as well as a dramatic reduction in gas prices and fewer generation outages in California, are among the factors that have had the effect of lowering energy prices in the West. Western power prices have fallen recently, with reports by the ISO citing peak daytime purchase costs of less than $100/MWh and off-peak power purchases of less than $20/MWh. During the week ending June 9, prices for last-minute peak power at Western trading hubs fell to less than $55/MWh from a high of about $170/MWh earlier in the week.[7] This trend continued into the week ending June 16 with prices hovering between $50/MWh and $65/MWh at most of the Western power indexes.[8] In addition, prices for Western forward contracts are also down dramatically, with year 2002 forward transactions dropping from $127 to $68/MWh, and 2003 forward contracts from $60 to $41 in the past month.[9]

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[7] Platts Power Markets Week, June 11, 2001. Prices of Spot Electricity, Week Ending June 9 – Daily On-Peak Indexes for Calif-Ore Border, Mid-Columbia, Palo Verde, Four Corners, North Path 15, and South Path 15 (Six Western Indexes).

[8] Megawatt Daily's Market Report, June 11 through June 14, 2001, for Six Western Indexes.

[9] Platt's Power Markets Week, June 11, 2001, pp. 1, 16. As used throughout this document, "forward contracts" or "forward transactions" means any transactions with a future delivery

(Continued on following page)

While progress has been made in correcting market dysfunctions, the dysfunctions will not be fully corrected until additional load is moved from the spot market to longer-term contracts (a mixed portfolio of supply contracts) and the basic structural defect of inadequate supply in the West is corrected. The Commission therefore has determined that in order to ensure that rates for sales for resale in spot markets in California and the rest of the WSCC continue to fall within a zone of reasonableness, we will provide for price mitigation in California and throughout the remainder of the WSCC during reserve deficiency hours, *i.e.*, when reserves in California fall below 7 percent (in California, Stage 1 is called when reserves fall below this level).[10] As we found in our April 26 Order, this is when the level of demand approaches the amount of available supply and suppliers have the greatest opportunity to exercise market power. In addition, based on the continents received and based on prices that we recently have observed in California in hours where there is no reserve deficiency, we conclude that as an added measure in protecting customers, at this time it is also appropriate to provide for a type of price mitigation for spot market sales during other hours.

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that are entered into more than 24 hours before commencement of service.

[10] Our April 26 Order referred to Stage 1 being called by the ISO when reserves in California fall below 7.5%. The correct number is 7%.

As noted, we find it appropriate to provide for price mitigation in the spot markets in California and throughout the West in reserve deficiency hours, *i.e.*, when reserves fall below 7 percent in California. As we found in our April 26 Order, at these times supply is scarce relative to demand and sellers have the greatest ability to dictate price. The price mitigation we will adopt for these hours will be based on market principles and will apply to California and the remainder of the West. Because there is no centralized clearinghouse for spot market sales in the WSCC other than in the ISO, and therefore no ability to develop a separate market clearing price for sales outside the ISO, we will apply the ISO market clearing price as the maximum price to all sales in the WSCC spot markets during reserve deficiency hours (Stage 1 or above) called by the ISO. We expect prices to be below this level to reflect the degree to which supply exceeds demand. Thus, our mitigation will apply to all sellers in the WSCC, including marketers and non-public utilities. It is critical to treat all sellers alike to remove the incentive to sell in one area versus another when a reserve deficiency is called by the ISO. We also will allow sellers other than marketers the opportunity to justify prices above the market clearing price during reserve deficiency hours and we will provide guidance on the specific showing that a seller must make.

In non-reserve deficiency hours, when supply is not scarce, prices should be disciplined sufficiently and should reflect an accurate measure of the

shortage confronting the West and provide a clear price signal to induce new supply. However, commenters are concerned that prices may remain high in hours when reserves are adequate. There is little doubt that regulators are ill-equipped to replicate the premiums which a functioning market assigns to a diminishing supply. It is precisely for this reason that, in our April 26 Order, we did not attempt to develop an administratively determined component for shortage and chose instead to rely on prices in non-reserve deficiency hours to send the correct price signal. Nevertheless, at this time, we will implement price mitigation in non-reserve deficiency hours as well. However, we will use a modified form of our present mitigation during non-reserve deficiency hours – to ensure that prices will continue to induce new supply. We do so as a discretionary matter to provide an added measure to protect customers and the economies of the Western states, even though we view prices above the marginal cost of generation in these hours as a necessary reflection of the supply shortage at hand. Instituting mitigation in these hours will protect customers so that all energies and attention can be harnessed on the tasks of adding new supply and upgrading energy infrastructure and of completing California's transformation from 100% reliance on the spot market to a balanced portfolio of short, medium and long-term supply arrangements, as well as protecting neighboring states from undue harm. Later in this order, we direct the State of California and parties in the *San Diego Gas & Electric Company* complaint proceeding to settlement

proceedings to complete the task of settling past accounts and structuring the new arrangements for California's energy future. We will monitor our price mitigation in non-reserve deficiency hours to ensure that it is providing the incentives needed to correct the present market dysfunctions. We will adjust the mitigation, as needed, to induce long-term supply entry and the forward contracts required to support that entry.

The price mitigation we are adopting again relies on market solutions and mechanisms to the maximum extent possible. We will continue to use a single market clearing price derived from must offer and marginal cost bidding requirements for hours of reserve deficiency in California's organized spot market. We also will adapt these market clearing prices for use in all other hours, both in California's spot markets and the West's spot markets. Before describing in general the price mitigation that will be required in the ISO's markets and in the bilateral spot markets in California as well as the rest of the West, we believe it is important to enumerate the major considerations we have balanced in developing appropriate price mitigation.

- There is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets.

- Uniform price mitigation for California and the balance of the West should reflect the same

essential competitive market principles, while recognizing the significant differences in the structure of those markets. It also should eliminate incentives for so-called "megawatt laundering".[11]

- In exercising our statutory responsibility to ensure just and reasonable rates, *i.e.*, rates that fall within a zone of reasonableness, we must balance the need for immediate price relief for customers against the need for price signals to attract new supply and demand-side investments.

- As mentioned in our prior orders, the cornerstone of remedying the dysfunctions in the energy markets in the West and in bringing both spot and forward prices down over the last few months is eliminating California's excessive reliance on spot markets. While significant progress has been made, some 20 percent of California's load remains in the ISO's spot markets at peak periods.[12]

- Buyers and sellers need certainty and closure. To the extent possible, our price mitigation should have clear rules, should set prices before they are charged and should not subject prices to change or adjustment after financial settlement of the day's transactions. Similarly, it should not rely on costly

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[11] The term "megawatt laundering" describes behavior where a supplier schedules supply out of state and then re-imports that power to avoid a mitigated price.

[12] Recent data indicates that the reliance on the spot market is higher during off-peak periods.

and time consuming administrative processes to set, adjust or justify prices.

- Abuse of market power cannot and will not be tolerated. Sellers will be subject to losing their market based rates for engaging in anticompetitive conduct. Further, as a condition of continued authorization of market-based rates, public utility sellers in the WSCC must agree to refunds, with interest pursuant to 18 C.F.R. § 35.19a, of any overcharges resulting from anticompetitive bidding or behavior.

To satisfy these principles, the mitigation plan will consist of the following measures:

- We will retain the use of a single market clearing price with must offer and marginal cost bidding requirements for sales in the ISO's spot markets in reserve deficiency hours, *i.e.*, Stage I when reserves are below 7 percent in California. Sellers in the ISO's single price auctions will receive the hourly market clearing price. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC) we will apply this clearing price as a maximum price. Sellers outside the ISO's single price auction will receive the prices they negotiate up to this maximum price. There are, however, three adjustments to the clearing price methodology we have previously used.

  First, marketers will be required to bid as price takers. This means that marketers cannot bid higher than the market clearing price.

> Second, we will require sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation (*i.e.*, what the seller would pay to procure gas at the last minute) plus variable O&M costs.
>
> Third, we instruct bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs and direct the ISO to file a rate mechanism to bill those costs over the entire load on the ISO system. These cost inputs have proven too varied to standardize in a single market clearing price.

Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will provide guidance later in this order on what sellers that seek to do so must demonstrate.

• For spot market sales, both in the WSCC and in California, in all non-reserve deficiency hours (*i.e.*, when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can

be no higher than $119/MWh (*i.e.* 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh.[13] For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward as the new maximum price. Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will later in this order provide guidance on what sellers that seek to do so must demonstrate.

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[13] As we explain later, the ISO is required to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. This adder will not be reflected in the market price for the rest of the WSCC.

- The mitigation plan will become effective beginning on the day following the date this order is issued.[14]

- We will continue to apply all price mitigation to non-public utilities as a condition of selling into the spot markets which are the subject of this order and as a condition of using the interstate transmission grid under our jurisdiction.

- We will reaffirm that all public and non-public utilities who own or control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled (or committed for minimum operating reserves) for delivery in the hour. We will also require all public and non-public utilities in the remainder of the WSCC to offer in the spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is also not scheduled (or committed for minimum operating reserves) for delivery in the hour.

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[14] We will grant waiver of notice for the ISO's approved rate mechanism to recover the cost of emission requirements to be effective on the day following the date this order is issued. Absent a new reserve deficiency on the ISO's system declared before the effective date of the price mitigation outlined in this order, the market clearing price carried forward for non-reserve deficiency hours is $108.49/MWh (*i.e.* 85 percent of $127.64/MWh) (May 31, 2001, clock hour ending 1400).

- The price mitigation will terminate on September 30, 2002.

- We will establish settlement proceedings at this Commission to address any and all issues to ensure that California completes the transformation of its load to long-term contracts. The Parties in the *San Diego Gas & Electric Company* complaint proceeding and the State of California are directed to participate in good faith in these proceedings.

We emphasize that the rate mitigation prescribed in this order is part of a series of steps the Commission has taken to remedy dysfunctions in California wholesale power markets. However, as we recognized in our first remedial order on December 15, 2000, many of the critical remedies that need to be taken fall either wholly or in part within the jurisdiction of the State of California. In particular, the consummation of additional long-term wholesale contracts, the development of demand side response signals, the siting of new generation and transmission, and the construction of intrastate natural gas delivery infrastructure are critical to remedying the current market dysfunctions and are dependent on State action. We recognize the significant progress that California has made thus far and urge further implementation of these critical measures. We stand ready to assist in these efforts to the extent possible within our authority.

Finally, in taking action in today's order as well as in prior orders in these dockets, beginning on

December 15, 2000, the Commission has taken careful, reasoned steps to fulfill its statutory responsibilities under the FPA. The Commission's statutory responsibility to set just and reasonable rates gives it broad authority to adapt its ratemaking policies to the practical realities facing it. The Supreme Court ruled very early on that individual company cost-of-service rates were not the *sine qua non* of rate regulation, and that no single method of ratemaking is sacrosanct as the only means to reach the statutory goals. Rather, the value of any ratemaking policy is to be judged by its ability to meet the statutory goal of assuring that rates remain within a zone of reasonableness consistent with the maintenance of adequate service.

The ratemaking power granted the Commission under the FPA includes the authority to set the rules, regulations, practices, and contracts affecting rates, as well as the rates themselves. The Commission's orders related to the California markets have sought to establish a structure within which market forces will operate to achieve the statutory goal. In this order, the Commission continues the efforts of its earlier orders to modify the existing market structure throughout the West to minimize the potential for market power abuse, and thus to protect against possible unjust and unreasonable rates, while, at the same time, maximizing the incentive for increased supply in the entire western region.

I. Background

In an order issued August 23, 2000,[15] the Commission instituted formal hearing proceedings under section 206 of the FPA to investigate the justness and reasonableness of the rates for energy and ancillary services of public utility sellers into the ISO and PX spot markets, and also to investigate whether the tariffs, contracts, institutional structures, and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. These proceedings were intended to investigate the significant increases in the prices for energy and ancillary services in the California market.

In the December 15 Order, the Commission found that the market structures and rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy under certain conditions. The Commission, therefore, established a variety of remedies for the California wholesale electric markets, which included, in part, elimination of the mandatory PX Buy-Sell requirement, establishment of penalties for underscheduling load, a requirement for an independent governing board for the ISO, and a requirement

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[15] San Diego Gas & Electric Company, *et al.*, 92 FERC ¶ 61,172 at 61,606 (2000) (August 23 Order).

for the filing of generation interconnection procedures.

As an interim measure, the Commission also established a $150/MWh breakpoint under which public utility sellers bidding above the breakpoint receive their actual bids, but are subject to monitoring and reporting requirements to ensure that rates remain just and reasonable, including the potential for having to pay refunds for prices charged above the breakpoint.[16] The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001.

On January 23, 2001, the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convened a technical conference to develop a plan to replace the interim breakpoint price.[17] Comments and reply comments on how to replace the interim break-point were filed with the Commission. In March 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market, and comments were filed on this proposal. The comments focused in particular on the method used for price

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[16] On March 9, 2001, the Commission issued an order directing public utility sellers to provide refunds (or offsets to amounts owed) or to provide cost or other justification for prices that exceeded the breakpoint. 94 FERC ¶ 61,245 (2001), *reh'g pending*.

[17] 93 FERC ¶ 61,294 at 61,983, 61,996-97.

mitigation and the periods when mitigation would be applied.

On April 26, 2001, the Commission issued its order adopting a prospective monitoring and mitigation plan for real-time California wholesale electric markets. The Commission's plan included the following elements:

> It enhanced the ISO's ability to coordinate and control planned outages during all hours.
>
> It required sellers with Participating Generator Agreements (PGAs), as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours.
>
> It required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours.
>
> It established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.
>
> It required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue

to monitor generating unit outages and real-time prices.

It established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert, which is defined as having reserves of 7 percent or less. Under this mechanism, the Commission established a formula (based on gas-fired generation) that the ISO can use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In the April 26 Order, the Commission also established an inquiry into whether a price mitigation plan similar to the one for California should be implemented in the WSCC. The order invited comment on how such a plan should be structured.

The parties listed on Appendix A have filed for rehearing of the April 26 Order. A number of parties have filed motions for late intervention. While the Commission ordinarily does not permit late interventions after an order has been issued solely to file for rehearing, the Commission will grant the late interventions in this instance because of extensive overlap of the issues between the California-oriented parts of the April 26 Order and the West-wide investigation instituted in that order, and the fact that the April 26 Order authorized additional comments and interventions for purposes of the latter. Appendix B lists those

filing comments in the section 206 proceeding with respect to the WSCC.

II. Discussion

As described earlier, the Commission is adopting a mitigation plan covering both California and the remainder of the WSCC during all hours for spot market sales. In the following sections, the Commission will address the rehearing requests and the West-Wide comments relating to this mitigation plan.

A. Outage Coordination

The April 26 Order found that in order to maintain sufficient generation capacity to meet market needs, the ISO must work with California generators to coordinate generating unit maintenance and outages, so that sufficient energy will be available when needed while also providing for reliable plant operation. The order required the ISO to make a tariff filing proposing a mechanism for outage coordination. The ISO made its compliance filing on May 11, 2001.

Most parties are in favor of such outage coordination. The CPUC, however, states that procedures relating to outage control and coordination are within the state's jurisdiction. CAC/EPUC contends that outage coordination may unreasonably burden QF facilities, because their outages are affected by their thermal host. DWR contends the outage controls should not be applied to hydroelectric generators.

Duke, on the other hand, protests the ISO's proposal and asks the Commission to clarify the need for truly cooperative standards and procedures.

The ISO has the authority to coordinate and control generation outage schedules for resources under PGAs. The Commission clarifies that only the ISO's outage coordination role will be extended to all other in-state generating facilities insofar as these generators must submit to the ISO maintenance schedules for their generating units. This will provide the ISO with the information necessary to maximize the efficient use of all in-state resources. For example, with this information, the ISO will be able to determine whether to schedule generation under its control based on when other generation resources will be out-of-service. The ISO, however, will not be authorized to schedule maintenance for units not under a PGA.

B. Selling Obligations

The mitigation plan requires those generators with PGAs, as well as non-public utility generators in California selling through the ISO markets or using the ISO's transmission lines, to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run. This must-offer obligation does not apply to power scheduled to run under bilateral agreements. The must-offer obligation does not apply to hydroelectric power because of its multi-purpose limitations (*e.g.*, irrigation,

recreation, and power production). The must-offer obligation is designed to prevent withholding and thereby to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. The basis for this requirement is that, under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time. The rehearing requests raise a number of issues that will be addressed below.

1. Applicability to Non-Public Utility Generators

A number of non-public utility entities request rehearing of the requirement that, because they make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), they must offer all their available power in real time during all hours. They primarily argue that the Commission is overstepping its jurisdictional bounds by asserting jurisdiction over them in violation of section 205 of the FPA.

CMUA, SMUD, and others contend that the Commission lacks jurisdiction over municipalities and other state agencies. CMUA maintains that "as far back as 1998, CMUA members have voluntarily made units available to the ISO, have sold the ISO energy on a regular basis in response to reliability calls, and continue to sell to creditworthy buyers."

CMUA at 8. CMUA contends that there is no evidence that such facilities are refusing unreasonably to sell in the ISO's markets.

The Commission denies the requests for rehearing. The Commission is not asserting jurisdiction over non-public utilities. Rather, as the Commission explained in the April 26 Order, it is exercising its conditioning authority to assure that all generators located in California, including non-public utility generators, that voluntarily sell into the ISO's spot market or that use the ISO's interstate transmission grid, offer their available power in California.[18] As we stated in the April 26 Order, if a non-public utility makes sales into the ISO's markets over which the Commission has exclusive jurisdiction or uses the ISO-controlled interstate transmission facilities, it must abide by the same conditions that are applicable to public utilities.[19] On rehearing, parties have raised no arguments that warrant a different result. We cannot meet our statutory responsibilities under the FPA to ensure just and reasonable rates in the Western spot markets if we allow non-public utilities to participate in the ISO's markets and use interstate

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[18] San Diego Gas and Electric Company, *et al.*, 95 FERC ¶ 61,115 at 61,356 (2001).

[19] *Id.* Since CMUA members already sell power on a regular basis to the ISO, and are assured of recovering their marginal costs when they run pursuant to the must-offer obligation, CMUA has not demonstrated that the Commission's actions would have an adverse effect on them.

transmission facilities, while refusing to comply with the measures necessary to ensure the justness and reasonableness of the ISO's rates and terms and conditions of service. In short, the Commission cannot ensure just and reasonable rates under the FPA unless non-public utilities, which sell power into the ISO's market or use the ISO's transmission lines, are subject to the same market rules as public utilities.

CAC/EPUC contends that imposing the must-offer obligation and the mitigation plan on QF facilities conflicts with the regulatory scheme established under the Public Utility Regulatory Policies Act of 1978 (PURPA). QFs that engage in sales for resale in interstate commerce and/or the transmission of electric energy in interstate commerce are public utilities and are therefore subject to the Commission's jurisdiction, although the Commission has exempted them from many provisions of the FPA.[20] However, because of the need for uniformity among all sellers, the Commission will not exempt QFs from the must-offer obligation and mitigation plan to the extent that QFs use the ISO's interstate transmission lines and make

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[20] Section 210(e) of PURPA states the Commission shall prescribe rules under which QFs are exempt, in whole or in part, from the FPA, PUHCA, and from state laws and regulations respecting rates or financial or organizational regulation. 16 U.S.C. § 824a-3 (1994). The Commission exempted most QFs from portions of the FPA, 18 C.F.R. § 292.601 (2000), PUHCA, 18 C.F.R. § 292.601(b) (2000), and from state laws and regulations respecting rates and financial and organizational regulation, 18 C.F.R. § 297.601(c) (2000).

sales through the ISO's markets.[21] The exemptions from regulation granted pursuant to PURPA to QFs do not mean QFs must or should be exempted from the must-offer obligation.

2. Extent of the Must-Offer Obligation

The predominant issue raised on rehearing is how to apply the must-offer obligation to thermal generators with environmental limitations on their operations. The April 26 Order stated that generators would not have to run if doing so would violate their certificate or applicable law. But it required those units to run if it involved only the paying of additional amounts to obtain emission credits to permit them to run outside their emission limitations.

A number of rehearings request clarification that generators do not have to run if doing so would violate certificates or subject them to possible criminal penalties or fines.[22] Sellers further maintain that units with maximum run limitations have legitimate opportunity costs that the Commission has failed to recognize.[23] They recognize that the issue of energy limited units is complex,[24] but that the Commission's

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[21] CAC/EPUC filed a request to stay the application of the mitigation plan as applied to QFs. Given the resolution of the rehearing request, the request for stay is denied.

[22] Rehearing Requests by MID, M-S-R, NCPA, TANC.

[23] Rehearing Requests by Dynegy, Mirant, Reliant.

[24] See Rehearing Request by Reliant.

proposed emission credit adder does not fully take into account the costs imposed by forcing these plants to run whenever the ISO determines. They argue that they have traditionally managed these units to ensure that they run only during the times of the year when they are most valuable and that they should not be required to run at other times without adequate compensation for the revenues they forgo.[25] Mirant maintains that exempting hydroelectric power from the must-run requirement while not exempting environmentally-limited gas units is discriminatory. Sellers maintain that the Commission should either eliminate the must-offer requirement or permit generators to include in their bids an amount to capture the economic value of losing the ability to generate in later years. Reliant maintains that application of the must-offer obligation to energy limited units should be conditioned on expansion of California Executive Order D-24-01 to sales into the ISO, so that run-time limits would not apply to such sales.

Municipals[26] similarly argue the Commission needs to make allowances for the possibility that imposing a must run obligation on a generator may impose additional price or cost risk at later periods of time. NCPA maintains that it is required to make use

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[25] For example, Dynegy maintains that forcing its units to run today will require it to use up emission credits allocated for the year 2003, and that it should be reimbursed for the lost opportunity of being unable to run that unit in the year 2003.

[26] Rehearing requests by NCPA, NRECA.

of its thermal plants to meet its member-customer needs and is concerned that if it is forced to run during particular periods, it may not be able to meet the power needs of its members in later periods, if it is unable to obtain additional emission credits. It therefore requests clarification that it not be required to honor the must offer obligation unless it is able to obtain additional air pollution credits and that it be permitted to include those credits in any bid it makes into the ISO. Municipal generators request clarification that they do not have to make power available to the ISO when that power is being used to serve their own retail load or is required as reserves under interconnection agreements.[27] They contend that the April 26 Order was not clear whether the requirement to serve retail loads would be considered the equivalent of bilateral contracts. CAC/EPUC contends the must-offer obligation should not be applied to QF facilities, because it interferes with the QF's obligation to its thermal host, which is governed by a contract or operational protocol. Calpine similarly argues that QF units with capacity committed to a utility are not subject to the must-offer even if it chooses not to operate at maximum capacity.

The Commission clarifies that generators should not be exempt from the must-offer requirement absent a showing that running the unit violates a

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[27] MID, M-S-R, TANC.

certificate, would result in criminal violations or penalties, or would result in QF units violating their contracts or losing their QF status. Many of these issues are within the domain of the State of California, and we strongly urge California to modify current policies to enable generators to run during this period of scarce supply. For municipal generators the must-offer obligation applies only to available power remaining after the municipality satisfies its own retail load and contractual obligations. Given the shortage of power in California, all generators in California, including municipals, should not hold energy in reserve (over minimum acceptable levels) when the energy is needed to meet demand.

For QF facilities, like other generators, the must-offer obligation applies to energy that is available from generation that is not already contractually committed or would not violate its contractual obligation to its thermal host. With respect to Calpine's argument, a QF with capacity committed to a utility is, therefore, subject to the must-offer obligation if it chooses not to sell its maximum output to the utility. With respect to CAC/ EPUC's contention, the Commission has granted waivers of the operating and efficiency standards so that QFs, without jeopardizing their QF status, can generate power regardless of whether the host needs thermal energy.[28] Therefore,

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[28] *See* San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,238 at 61,772 & n.3 (2000) (December 8 Order) (granting temporary waiver of QF

(Continued on following page)

QF facilities will be expected to produce available energy regardless of whether the host requires thermal energy.

Due to the severity of the power shortage in the WSCC in general, and in California specifically, the Commission finds that the incurrence of expenses for obtaining additional emission allowances is not a valid reason to withhold available energy from the ISO's market. As discussed later in this order, the Commission is providing a mechanism for generators that incur emission related expenses to recover those costs through the ISO. Moreover, the Governor of California signed an Executive Order, D-40-01, allowing generators to exceed their emission runtimes without losing valuable future emission allowances, provided the energy is sold to DWR (or another California buyer) or dispatched by the ISO. Therefore,

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regulations); San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 at 62,018 (December 15 Order) (extending waivers); Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,970-71 (March 14 Order) (extending QF waivers); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 at 61,767-68 (2001) (May 16 Order) (waivers extended to entire WSCC and through April 30, 2002). In a second order issued on May 16, the Commission required California Utilities to provide interconnection and transmission service to QFs pursuant to existing agreements to permit certain sales of QF power to third-party purchasers. San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,226 (2001).

exceeding today's emission limits will not affect future limits. Thus, Executive Order D-40-01 moots all arguments on this issue insofar as California generators are concerned, including those of the municipal generators.

3. Withholding Generation for Operational Reasons

Mirant, Reliant, and Williams maintain that the must-offer obligation fails to recognize the need to withhold generation to cover the possibility that a unit will unexpectedly go offline. They take issue with the statement in the April 26 Order that a generator cannot be financially harmed from offering all of its units because the generator will only have to pay for the cost of replacement power, which is the same amount the generator would earn if the unit ran. They argue that, while this statement is true in theory, it does not apply to the ISO's markets because due to penalties in the ISO's tariff and the manner in which the ISO computes the cost of replacement energy, the generator would have to pay more for replacement energy than it would receive for the unit's bid in the market.

The must-offer obligation is crucial to ensuring that all capacity is in the market when needed and tariff provisions should not inhibit the fulfillment of this obligation. The Commission finds that during the periods mitigation is in effect, the current ISO tariff provisions in this regard are unjust and

unreasonable, and, therefore, we will require the ISO to modify its tariff, to be effective the day after the date of this order, so that the only penalty for having a unit forced out of service is the cost of replacement energy. The must-offer obligation modifies various market rules that existed when the current penalty provision was accepted for filing.

4. Other Issues

Several rehearing requests are concerned about generators avoiding the must-offer requirement through so-called "megawatt laundering" where a generator sells power to an out-of-state marketer, who then reimports that power to avoid a mitigated price.[29] The Commission clarifies that the must offer obligation applies to all sellers who own or control generation by contract. Moreover, the mere fact that a generator has a contract to provide power to a marketer does not exempt the generator from the must-offer obligation for energy that the marketer is not scheduling. As long as the generator has available energy, the generator has the obligation to offer that power into the ISO's auction market. Moreover, as described later, all marketers in the ISO's markets must now be price takers and cannot justify a bid higher than the mitigated price.

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[29] Rehearing Requests by ISO, CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

Dynegy maintains the must-offer obligation should be limited to emergency hours only. It argues that had this obligation been imposed at the time it purchased the plants, it would have paid a lower amount. It therefore contends the must-offer obligation unfairly changes the contractual conditions under which it purchased the plants. The Commission rejects Dynegy's argument. The must-offer obligation must be applied in all hours in order to ensure that all available capacity is in the market and that none is being withheld, except for the reasons previously discussed. Moreover, mitigation is now being applied in all hours, so the must-offer obligation must also be applied to all hours.

LADWP requests clarification that the must-offer and price mitigation aspects of the order do not apply to its sales of energy under bilateral contracts or to sales or purchases that are scheduled to run in real-time pursuant to a bilateral contract. All public and non-public utilities which control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract only to the extent its output is not scheduled for delivery (or committed for minimum operating reserves) in the hour. All public and non-public utilities in the remainder of the WSCC must offer in a spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled for delivery (or committed for minimum operating reserves). All sales in these spot

markets are subject to the price mitigation established in this order.

The rehearing requests raise issues with respect to the effect of the must-offer obligation on the ISO's authority to curtail exports of power to other markets. Reliant and Mirant maintain the must-offer requirement should supplant the ISO's curtailment authority under its tariff. Reliant contends the curtailment authority is unnecessary now that California generators will be bidding all available supply into the real-time market. Williams maintains the ISO should compensate generators for curtailments. SDG&E, on the other hand, contends the Commission should permit the ISO to curtail in-state generation destined for other states.

The Commission is not persuaded to change the ISO's curtailment authority at this time. Since Reliant maintains that this authority is no longer needed as a result of the must-offer obligation, it has not demonstrated how it is harmed by leaving the current authority intact. The price mitigation adopted in this order establishes the same price throughout the WSCC as in California, and therefore does not provide a financial incentive for generators to sell energy outside of California. Parties may renew objections to this authority in future proceedings if they can establish discernible harm.

C. Demand Response

The April 26 Order provided that beginning on June 1, 2001, each public utility purchasing electricity in the ISO's real-time market is required to submit demand-side bids that will indicate the price at which load will be curtailed and will identify the load to be curtailed.

The ISO requests clarification as to whether the demand response mechanism is voluntary or mandatory. If voluntary, the ISO maintains that it is already implementing a number of demand response mechanisms, If the requirement is mandatory, a number of rehearing requests contend that it is insufficient to solve the problem,[30] and is technically infeasible, in the short-run, because there is no mechanism for obtaining accurate demand response signals from all customers. In addition, the ISO cannot currently curtail power to individual loads.[31] Parties assert that load serving entities should not be required to simply guess at the prices its customers are willing to pay. SDG&E, for example, contends that the CPUC did not permit it to act as an aggregator for demand responses, and accordingly it would simply be guessing at what price its customers are willing to pay. San Francisco maintains that curtailing retail customers is anathema to the Load Serving Entities' (LSEs') duty to serve. A number of

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[30] See Rehearing Request by CMUA,

[31] Rehearing Requests by ISO, DWR, San Francisco.

requests contend that demand response is a state concern, and the Commission has no authority to indirectly regulate retail customers. Others contend that since the DWR is not a public utility, it would not be covered by the demand response mechanism in any event.

On the other hand, generators maintain that a demand response mechanism is crucial to establishing a viable market and is needed to provide generators with appropriate scarcity rents.

The Commission continues to believe that establishing a demand response mechanism is crucial to establishing a robust market.[32] Without a demand response mechanism, the ISO is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power. There is ample evidence that this is not true. Many customers, given the right tools, can and will manage their demand. Such an assumption inevitably leads to higher prices during times of shortage, since high supply bids do not lead to a reduction in power purchased. A working demand response program puts downward pressure on price, because suppliers have additional incentives to keep bids close to their marginal production costs and high supply bids are

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[32] *See* Chandley, Harvey, & Hogan, Electricity Market Reform in California, at 25 ("The least controversial reform of market design would be to implement all the changes needed to allow for demand side response in the face of higher prices." (Attached to November 22, 2000 Comments of SDG&E).

more likely to reduce the bidder's energy sales.[33] Appropriate price signals to customers thus helps to mitigate market power as high supply bids are more likely to reduce the bidders' energy sales, Suppliers thus have additional incentive to keep bids close to their marginal production costs. Demand-side price-responsive bids will also help to allocate scarce supplies efficiently.

Indeed, without demand-side price responsiveness, there can be no market mechanism for ensuring that scarce supplies are allocated to the highest valued uses during shortages. However, based on the technical impracticalities raised in the rehearing comments, the Commission does not find that the demand response requirement should be implemented at this time. Because the development of demand response is so critical, we expect that buyers in the ISO's market will submit demand bids as soon as demand bidding becomes technologically feasible. Meanwhile, the Commission will continue to monitor developments in California to determine whether additional Commission action is needed. The ISO must include in its quarterly reports a discussion of all demand response changes that have been

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[33] Already conservation has helped to reduce demand. *See* Peter Behr, "Fears of an Energy Crisis Begin to Dim, Consumption Cuts Help Lower Prices for Gasoline, Natural Gas and Electricity," Washington Post, April 8, 2001, at E1 (California has reduced demand 8%). A properly designed demand side response program could improve this performance even more markedly by providing price incentives for reduction.

implemented. If state programs for demand response do not develop, the Commission expects the ISO to enhance its own programs.[34]

Public utilities along with California officials also must actively pursue such approaches to achieving a viable demand response program. As SDG&E points out, LSEs can effectively act as aggregators for retail demand response. SDG&E and other public utilities should continue to pursue demand response initiatives and are required to file with the Commission by September 14, 2001 a report of the progress that is being made in establishing these mechanisms and any difficulties they have encountered.

To help facilitate these initiatives, the Commission intends to conduct a staff technical conference to explore how demand response can be increased. The first purpose of the conference will be for the Commission to familiarize itself with the status and availability of conservation, demand-side management, and other innovations to help communicate real-time price signals to consumers, including the software and metering necessary to support such programs. The second purpose will be to explore how these programs can be implemented. At the conclusion of

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[34] Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,972-73 (March 14 Order) (DSM programs); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 (2001) (May 16 Order).

the conference, the Commission will reconsider the feasibility and schedule for a demand bidding requirement and its use in establishing prices in the ISO's market.

D. Price Mitigation for California and the WSCC

The April 26 Order applied price mitigation to periods of reserve deficiency, defined as those periods beginning with Stage 1. Under the approach set forth in the April 26 Order, the ISO would conduct a market clearing auction for its real-time markets. During periods of reserve deficiency, however, the ISO would calculate a marginal cost bid for each generator by using a proxy for the gas costs, emission cost, and operation and maintenance (O&M) expenses. The ISO would then use the bid of the last unit dispatched to establish the market clearing price. The justification for this approach is that as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus, sellers have an incentive to offer supply at prices above that which they would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable. The Commission, however, did not impose mitigation during periods of reserve sufficiency because there is less risk that prices would exceed those charged in a competitive market. During reserve sufficiency conditions a supplier has less of an incentive to bid a high

price, because it cannot be sure it will be dispatched, since other generators may offer lower bids.

Many rehearing requests, as well as comments in the West-Wide proceeding, contend the Commission should have extended mitigation to cover all hours. They contend that evidence from a number of studies shows that sellers have been able to exercise market power during all hours. They contend that the Commission has the obligation under the FPA to assure just and reasonable rates in all hours.[35] Duke Energy and other generators insist that the record does not show that market power has been exercised.

As described earlier, the Commission here is instituting a two-part approach to price mitigation for spot markets to cover all hours for California and the WSCC. Because these markets are integrated, the mitigation proposal must establish the same prices for all markets in order to prevent arbitrage where power is diverted from the lower priced market to the higher priced. The mitigation plan further has to recognize the differences between the California market, which has an organized auction, and the remainder of the WSCC, which does not have a similar centrally organized market. The plan adopted by the Commission is tailored to provide a uniform scheme of mitigation that at the same time recognizes the

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[35] Rehearing Requests by ISO, CEOB, CMUA, Assembly, City of Anaheim, *et al.*, CFA, Metropolitan, PG&E, NCPA, SDG&E, San Diego, San Francisco, Seattle, Edison, SCWC.

differences between these markets. During non-reserve deficiency hours in California, the Commission will adapt the ISO's market clearing price for spot market use West-wide.

The purpose of instituting this dual plan is to stabilize the market in the short-term and permit California time to repair its market mechanisms. The shortage of hydroelectric power together with the failure to build efficient generation is clearly a major part *of* the problem. This has been exacerbated by the imbalance between high wholesale prices and low retail prices, which do nothing to dampen demand. What *is* clear, however, is that a major contributor to the high prices was the deficient market mechanisms initially established by California, and approved by the Commission, that have resulted in a dysfunctional marketplace both in California and the remainder of the West. The mitigation plan established in this order, in effect, provides breathing room for the markets to right themselves.

The ISO, CPUC, and PG&E further contend that mitigation should apply outside of the ISO's Imbalance Energy market and should include its Day-Ahead and Hour-Ahead markets for ancillary services and its congestion management market. The Commission's order providing clarification and preliminary guidance addressed these issues.[36]

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[36] San Diego Gas & Electric Company, *et al.*, 95 FERC ¶ 61,275 (2001).

Several rehearing requests contend the mitigation should apply to all bilateral contracts.[37] The section 206 proceeding involving the ISO was limited to the ISO's and PX's real-time markets and did not extend to bilateral markets.[38] As discussed, however, in the Commission's section 206 investigation of the non-ISO spot markets in the WSCC, we have determined it appropriate to also apply mitigation to the bilateral spot markets in the WSCC, including California. Parties have not provided justification for extending the scope of our investigation or the mitigation to bilateral transactions other than spot markets. Moreover, any mitigation applied to the ISO's real-time markets will, over time, impact bilateral and forward markets as well.

A number of parties argue that the Commission's market monitoring and mitigation plan will not result in just and reasonable rates as required by the Federal Power Act, and the Commission should either return to individual cost-of-service rates or condition the continued use of market-based rates on effective mitigation measures.[39] The CPUC maintains that because the Commission found rates to be unjust and

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[37] Rehearing Requests by CPUC, City of Anaheim, *et al.*, PG&E.

[38] San Diego Gas & Electric Company, *et al.*, 93 FERC ¶ 61,121, at 61,349 (2000) (limited proceeding to real-time markets).

[39] *See, e.g.*, ISO, CEOB, CPUC, Assembly, CFA, PG&E, San Francisco, Seattle, and Edison.

unreasonable, the Commission is required to fix by order just and reasonable rates. It declares that "[w]here, as here, market power is pervasive through the industry in the west, FERC must impose cost of service pricing."[40] PG&E asserts that the Commission should immediately suspend the existing market-based rates of all sellers in the West and that the Commission should require immediate cost of service filings.[41] CEOB maintains that "[t]he Commission has no choice but to engage in cost-based ratemaking, or to adopt a sweeping mitigation scheme throughout the WSCC to ensure just and reasonable rates. . . ."[42]

Since determining that the market structure and rules for wholesale sales of electric energy in California had caused, and continued to have the potential to cause, unjust and unreasonable rates for short-term energy during certain times and under certain conditions, the Commission has ordered changes to the market structure and rules to assure that future rates would be just and reasonable.[43]

After carefully considering the record, the Commission reaffirmed its general finding that, as a result of the seriously flawed electric market structure

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[40] CPUC Request for Rehearing at 7.

[41] PG&E Request for Rehearing at 13-15.

[42] CEOB Request for Rehearing at 4.

[43] FERC's remedial measures "must be construed as a whole in, assessing FERC's compliance with FPA § 206". In re California Power Exchange Corp., 245 F.3d 1110, 1120 (9th Cir. 2001).

and rules for wholesale sales of electric energy in California, unjust and unreasonable rates were charged, and could continue to be charged during certain times and under certain conditions, unless certain targeted remedies were implemented. *San Diego Gas & Electric Co., et al.* 93 FERC ¶ 61,294 (2000) ("December 15 Order").[44]

The following remedies were adopted by the Commission in order to correct the specific flaws identified through the investigatory and hearing process: (1) because "the mandatory participation requirement . . . [was] producing rates that [were] not just and reasonable during certain periods," the Commission eliminated the requirement that the IOUs sell all of their generation into and buy all their energy needs from, the PX; (2) recognizing that it could assure the justness and reasonableness of California wholesale markets prices only by eliminating the PX's exclusive mandatory exchange, the Commission terminated the PX's wholesale tariffs; (3) to

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[44] The Commission has freedom, "within the ambit of [its] statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. "FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942); In re California Power Exchange Corp., 245 F.3d at 1120. FPA § 309, 16 U.S.C. § 825h, gives the Commission the necessary flexibility to take unusual remedial action in appropriate circumstances. *See* Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) (applying NGA § 16, the counterpart of FPA § 309, the Court held that "the Commission's broad responsibilities . . . demand a generous construction of its statutory authority."); FPC v. Louisiana Power & Light Co., 406 U.S. 621, 642 (1972) (same).

eliminate market participants' chronic underscheduling with the ISO, which jeopardized ISO system operations and created a strong sellers' market and higher prices in the most volatile spot market (real-time imbalance), the Commission required market participants to preschedule 95 percent of their load, with penalties for scheduling deviations in excess of five percent of an entity's hourly load requirements and disbursements of penalty revenues to all loads scheduled accurately; (4) mindful that eliminating the mandatory buy/sell requirement would move a considerable amount of load into the forward long-term markets all at once, the Commission established, effective for one year, an advisory benchmark for pricing five-year contracts; (5) because of concerns about the independence and effectiveness of the ISO governing board, the Commission ordered that the current stakeholder governing board be replaced by a non-stakeholder board composed of members independent of market participants; and (6) the Commission required the ISO and the IOUs to file generation interconnection procedures to facilitate the interconnection of new generators or existing, upgraded generators, thereby enhancing system reliability and reducing price volatility.

To further assure that prices in the ISO's and PX's spot markets are just and reasonable, the Commission directed that a technical conference be held to develop a comprehensive and systematic monitoring and mitigation program to be submitted to the Commission by March 1, 2001. Until that date,

the Commission established an interim $150/MWh breakpoint for spot market sales. On an interim basis, g public utility sellers bidding at or below $150/MWh would receive the market clearing price up to $150/MWh, and only those sellers bidding above $150/MWh would receive their actual bid price. However, all accepted bids above $150/MWh were required to be reported to permit proper monitoring and review by the Commission.

On April 26, 2001, the Commission adopted a prospective monitoring and mitigation plan for real-time California wholesale electric markets which replaced that previously in effect. The Commission's plan: (1) enhanced the ISO's ability to coordinate and control planned outages; (2) required sellers with PGAs, as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours; (3) required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours; (4) established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anti-competitive bidding behavior in the real-time market during all hours; (5) required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices;

(6) established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert (*i.e.*, when reserves are below 7 percent). This mechanism provided a formula (based on gas-fired generation) for the ISO to use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In this order, the Commission is expanding the market monitoring and mitigation plan to produce spot market prices in all hours that are just and reasonable and emulate those that would be produced in a competitive market. We find that a return to individual cost-of-service ratemaking is unwarranted. As addressed above, the market changes and monitoring procedures already implemented by the Commission have improved the wholesale power markets in California. This order continues that effective course. In contrast, cost-of-service ratemaking tends to penalize more efficient generators and not provide proper incentives for generators to become more efficient, since each generator's price is dependent on its costs.[45] Moreover, individual cost-of-service rates may not provide generators with appropriate scarcity rents. Establishing individual cost-of-service rates is also difficult with respect to spot markets. For

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[45] *See* National Rural Telecom Association v. FCC, 988 F.2d 174, 178 (D.C. Cir. 1993).

peaking units, decisions would need to be made about the number of projected MWhs over which to spread costs. Generators also would have to make filings establishing their rate base, acceptable rate of return, and cost-of-service, possibly including trackers for volatile costs such as gas and emissions fees. Resolving the issues involved in such filings would be protracted and would not provide price certainty to the market. We do provide for any generator unable to work within the revised mitigation framework the opportunity to apply for cost-based rates for the duration of the plan.

The monitoring and mitigation plan adopted by the Commission in this order satisfies the requirements of the FPA. In particular, FPA Section 206 allows the Commission to determine whether "any rate, charges, or classification . . . or any rule, regulation, practice, or contract affecting such rate, regulation or classification" is unjust or unreasonable, and to fix "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force." 16 U.S.C. § 824e(a) (1994). In this order, as in our earlier orders related to this matter, the Commission has examined the rules, regulations, practices and contracts that are currently being used, and made changes that are necessary to prevent possible abuses that could lead to unjust and unreasonable rates.

The focus on changes to the existing market structure, rather than on setting cost-of-service rates for individual sellers, is consistent with the case law.

As the Supreme Court made clear, it "has never held that the individual company cost-of-service method is a *sine qua non* of natural gas [or electric] rate regulation."[46] Nor has the Court limited ratemaking agencies "to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.'"[47] The success of a particular ratemaking approach is judged by "the result reached not the method employed."[48] The end result of any ratemaking order must be to provide rates within a zone of reasonableness that "take fully into account the probable consequences of a given price level for future programs of exploration and development".[49] As that language makes clear, a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty. Rather, the Commission must consider the broader public interest, and, in particular, the interest in setting rates that will assure adequate supply.[50]

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[46] Wisconsin v. FPC, 373 U.S. 294, 309 (1963).

[47] Permian Basin Area Rate Cases, 390 U.S. 747, 776-77 (1968).

[48] FPC v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944).

[49] Permian Basin, 390 U.S. at 797; *see* Atlantic Refining Co. v. Pub. Service Comm., 360 U.S. 378, 388 (1959) (same).

[50] Permian Basin, 390 U.S. at 796-97; Mobil Oil Corp. v. FPC, 417 U.S. 283, 317-18 (1974); Consumers Union v. FPC 510 F.2d 656, 660 (D.C.Cir. 1974); *see also* Central Iowa Power Coop

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The Commission is free to adopt market-based rates.[51] In adopting market-based rates, the Commission must: (1) provide a clear and reasoned analysis of the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a "zone of reasonableness."[52] Having adopted a market-based approach for the California market, nothing

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v. FERC, 606 F.2d 1156, 1165 n. 28 (D.C.Cir. 1979) (affirming rate based on "need to stimulate short-term purchases of excess capacity in lieu of adding new capacity and to discourage reliance on emergency energy when units are less than efficient").

[51] *E.g.*, Louisiana Energy and Power Authority v. FERC, 141 F.3d 364 (D.C. Cir. 1998); Elizabethtown Gas Company v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993); *see also* Midcoast Interstate Transmission, Inc. v. FERC, 198 F.3d 960, 968 (D.C.Cir. 2000). Other agencies subject to ratemaking regimes similar to that of the FPA have been upheld in adopting a market-based, rather than a cost-of-service, approach to setting rates. See Nat'l Ass'n of Regulatory Util. Comm'rs v. FCC, 737 F.2d 1095, 1137 (D.C. Cir. 1984); Nat'l Rural Tel. Ass'n v. FCC, 988 F.2d 174 (D.C. Cir. 1993); Consolidated Rail Corp. v. U.S., 812 F.2d 1444 (3d Cir. 1987); Potomac Elec. Power Co. v. ICC, 744 F.2d 185 (D.C.Cir. 1984).

[52] In Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), *cert. denied sub nom.* Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984), the court explained that it may not invalidate "rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'" It added that "when FERC chooses to refer to non-cost factors in ratesetting, it must specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates."

requires the Commission to revert to a cost-of-service ratemaking approach whenever it finds flaws in the market structure. *See, Environmental Action v. FERC,* 996 F.2d 401, 411(D.C. Cir. 1993) (finding that the Commission "has never bound itself to a rule requiring either rigid regulation or textbook markets"). The courts have also approved the use of marginal cost pricing as an appropriate regulatory tool. *Town of Norwood v. FERC,* 962 F.2d 20, 22 (D.C. Cir. 1992) (stating "one of the best-established precepts of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equivalent to the marginal cost of producing it.") See *Electricity Consumers Resources Council v. FERC,* 747 F.2d 1511 (D.C. Cir. 1984) (same).

Rather, in such circumstances, the presence of a monitoring program under which the Commission can take appropriate action to restructure the market is key. For example, in *Elizabethtown,* the court found that the continued "exercise of the Commission's NGA] § 5 authority . . . to assure that a market (*i.e.*, negotiated) rate is just and reasonable" sufficiently safeguards against abuses under a market pricing approach. 10 F.3d at 870. Similarly, in *Environmental Action,* the court approved the combination of price ceilings and complaint procedures as sufficient safeguards because that would allow "competitive forces, not market power, [to] determine most transaction prices . . . and serve to extend competitive pricing to

situations where market power might otherwise prevail." 996 F.2d at 413.[53]

Through the remedies ordered in earlier orders and herein, the Commission determined and is continuing to determine pursuant to FPA Section 206 "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract" to replace flawed structure and rules, and to "fix the same by order." The Commission was not obliged to set seller-specific cost-based rates to resolve the perceived problems, given its continuing monitoring and review of the situation which offers adequate safeguards against potential market abuse. The mitigation plan adopted in this order relies on market solutions and mechanisms to the maximum extent possible, consistent with the Commission's statutory responsibilities to maintain just and reasonable rates. The revisions made in this order are designed to provide a structure that will minimize potential market power abuses, thus lowering customer rates, while also encouraging adequate supply in the market for the immediate future.

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[53] The courts have approved market pricing for other agencies if available remedies assure that market power will not be abused. E.g., Ford Motor Co. v. ICC, 714 F.2d 1157, 1158-59 (D.C. Cir. 1983); Arkansas Power & Light v. ICC, 725 F.3d 716, 718 (D.C. Cir. 1984); Coal Exporters Ass'n v. U.S., 745 F.2d 76, 80 and 90 n. 18 (D.C. Cir. 1984); Arizona Public Service Co. v. U.S., 742 F. 2d 644, 647 (D.C. Cir 1984).

E. ISO Market Clearing Auction During Periods of Reserve Deficiency

Under the April 26, 2001 mitigation plan, each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. The ISO would use these heat rates to calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and a $2.00/MWh adder for O&M expenses. The gas cost proxy was based on an average of the daily prices published in Gas Daily for all California delivery points. The emission cost was to be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit. All generators would be paid a single market clearing price reflecting the last unit dispatched calculated using the proxy prices.

Rehearing requests addressed a number of elements of this plan. Based on those rehearing requests, the Commission, as discussed in detail below, is modifying the method of determining the cost for gas, the treatment of emission costs, and the O&M adder. The Commission will address below the rehearing requests with respect to the ISO auction mitigation plan.

1. Use of the Marginal Cost of the Last Unit Dispatched

PG&E maintains the Commission should not determine price using the marginal cost of the last unit dispatched. Instead, it maintains the Commission should use the heat rate of the average cost unit. PG&E maintains that in a competitive market, each unit of generation would recover only its own marginal costs.

In a competitive market, however, each generator would not receive only its own marginal cost, as PG&E asserts. Competitive markets clear at a single price, which is effectively set by the marginal cost of the last unit produced. All more efficient units will receive the same price, which creates an incentive for firms to increase their efficiency. Therefore, using the marginal cost of the least efficient generating unit dispatched best replicates prices in a competitive market. In 1998 and 1999, when the California spot markets were producing average annual wholesale prices of $29 and $31 per MWh, respectively, the marginal cost of the last unit dispatched set these prices. The mitigation plan simply returns the market to the competitive principles that existed in 1998-99.

The ISO contends that inflexible units such as combustion turbines should not set the proxy price, because they do not have the flexibility to be dispatched on a 10-minute basis. The Commission's mitigation plan is based on the payment of the marginal

cost of the last generator dispatched to serve the last increment of load. Therefore, if a combustion turbine is the last generator dispatched, its bid should establish the market clearing price.

2. Calculation of Market Clearing Price

Rehearing requests raise a number of issues with respect to the calculation of the mitigated price, particularly with respect to the gas prices and emission prices used.

a. Gas Costs

Under the Commission's April 26, 2001 approach, gas costs used in the formula are determined by an average of reported daily spot gas prices at California delivery points. The requests for rehearing raise a number of issues regarding the use of gas costs to determine the market clearing price. Several rehearing requests contend that the Commission should not use proxy prices, but should use actual gas (and emissions) costs for generators.[54] Others contend that using the reported gas prices overstates gas costs, because generators have a portfolio of gas supplies and are not buying all their gas at spot prices.[55] The ISO and CEOB contend that to better reflect supply

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[54] Rehearing Requests by NCPA, Seattle, Edison.

[55] Rehearing Requests by ISO, CPUC, Assembly, Metropolitan, PG&E, SDG&E, San Diego, San Francisco, Edison.

portfolios, the Commission should use monthly bid-week gas prices, rather than daily spot prices. The ISO recommends the Commission use bid-week monthly prices from Gas Daily, but for only three points in California, Malin, SoCal Gas (large packages), and PG&E city-gate (excluding PG&E large packages). Others contend that using the average gas price does not accurately reflect the marginal costs of generators, because as prices are higher at the Southern California points than Northern California points.[56] They suggest that the gas proxy price should be revised to more accurately reflect the marginal costs of each generator.

The Commission's mitigation plan is designed to establish generators' bids and market prices up-front. Using actual costs to determine marginal cost, as some suggest, would not establish generator bids, but would require an after-the-fact review of whether a generator's bid actually reflected its marginal cost. Using actual costs, therefore, would not provide price transparency, and would be administratively infeasible because it would require a constant reevaluation of every generator's bids.

The Commission will revise the spot gas prices to be used in the formula to accord with the requests by the ISO to establish the proxy gas cost for

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[56] Rehearing Requests by CEOB, Dynegy, Reliant, Williams.

determining marginal costs.[57] The ISO will be required to average the mid-point of the monthly bid-week prices reported by Gas Daily for three spot market prices reported for California.[58] This price represents a reasonable proxy for the marginal cost that generators will incur, since they can pre-buy their gas requirements for the month at this price.[59]

The Commission recognizes that, as Reliant and Dynegy point out, spot gas prices in southern California off of SoCal Gas's system exceed other spot prices in California. The staff of the California Energy Commission has recognized that a chief contributor to the high natural gas prices in southern California is the deficit of intrastate capacity on the SoCal Gas system.[60] It reports that the interstate delivery capability exceeds the ability of SoCal Gas to receive that gas by 300 MMcf/d. It concludes that:

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[57] *See* Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992) (one of the best established principles of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equal to the marginal cost of producing it); Electricity Consumers Resources Council v. FERC, 747 F.2d 1511 (D.C. Cir. 1984).

[58] The three points are SoCal Gas (large packages), Malin, and PG&E city-gate.

[59] The average for June as reported in the Gas Daily Price Guide is $9.10. The bid-week monthly index prices are SoCal Gas (large packages) $11.71, Malin $5.98, PG&E Citygate $9.61.

[60] California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

> this deficit in receipt capacity contributes to the high natural gas prices in California and the tight supplies to meet natural gas demand by electric generators.[61]

Another contributing factor to the high gas prices is the inability of generators and other shippers to acquire firm transportation rights on SoCal Gas's backbone system and SoCal Gas's system of allocating transportation on its backbone system, which leads to great uncertainty in scheduling gas supplies from interconnecting pipelines. This Commission recently has taken action to help improve the certainty of nominations on interstate pipelines into southern California,[62] but in the absence of scheduling changes on SoCal Gas, the Commission's changes to interstate scheduling practices cannot remove this uncertainty altogether. The Commission staff held a technical conference on May 24, 2001 to examine the problems in California gas infrastructure in which many participants continued to express concern about the lack of intrastate capacity on SoCal Gas and the difficulty in achieving certainty in scheduling gas supplies due to SoCal Gas's allocation

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[61] California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

[62] Amoco Energy Trading Corp. v. El Paso Natural Gas Company, 93 FERC ¶ 61,060 (2000), *aff'd* 94 FERC ¶ 61,225 (2001).

procedures.[63] The Commission also is continuing to pursue efforts to try to dampen these higher prices into southern California. For example, the Commission recently issued orders requesting comment on whether to establish reporting requirements to create greater transparency in the gas market for southern California and whether imposing a price ceiling on capacity release transactions would have an effect on dampening prices.[64] The Commission will continue to monitor the situation in California to see whether further efforts are needed.

In addition to the dysfunction in southern California gas markets, the Commission cannot be certain that the daily SoCal Gas (large packages) spot price represents the actual cost of southern California generators. Gas Daily and the other reporting services do not indicate what volume moves at these prices, how much volume may be sold at lower prices in non-spot markets, and whether generators may be able to use other options to protect themselves against such higher prices.

Because of these concerns about the supplies coming into California from SoCal Gas, the Commission

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[63] California Natural Gas Transportation Infrastructure, Docket No. PL01-4-000.

[64] Order Proposing Reporting Requirement on Natural Gas Sales to California Market and Requesting Comments, 95 FERC ¶ 61,262 (2001); San Diego Gas & Electric Company, *et al.*, 95 FERC ¶ 61,264 (2001).

does not find it reasonable to base the market clearing energy price for California and the remainder of the WSCC solely on the southern California spot price for gas. Instead, the most equitable way of handling this issue is to use the approach described above. Under the mitigation plan adopted in this order, individual southern California generators are permitted to justify bids above the market clearing price so long as they can show their entire gas portfolio justifies such a bid.

b. Emission Costs

The April 26 Order stated that the emission cost would be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for each unit. Many rehearing requests point out that the method of paying for exceeding emission allowances has been changed, so generators no longer can buy NOx emissions when they run out of emission allowances. Instead, local air districts now require generators to pay mitigation fees when they exceed their emission allowances.

Several rehearing requests contend that the emissions cost should not be included as part of the proxy price, but should instead be collected in an uplift charge when actually incurred.[65] Several also

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[65] Rehearing Requests by ISO, ARB, CEOB, CPUC, Assembly, PG&E, San Diego, SCAQMD, Edison, SCWC.

argue that not all generators pay emission costs and those that do incur such costs pay them only when they have used up their emission allotments.[66] They contend, therefore, that emissions costs should not be included until they have to be paid. ARB maintains that mitigation fees are not variable costs and should not be included in the marginal cost calculation because it will increase prices to all customers. It also argues that including mitigation fees as part of marginal costs will result in increased pollution as air districts may decide to reduce the emissions fees as a result of the higher consumer costs for power.

Sellers, on the other hand, contend that emissions costs are legitimately included as marginal costs.[67] They maintain that in running beyond their allotment of emission costs today, they not only are required to pay mitigation fees, but their emission allotments in subsequent years are reduced.[68] Sellers claim they need reimbursement for the opportunity costs of losing the ability to run their units in later years.

We will eliminate NOx costs from the calculation of the mitigated market clearing price. Since the Commission issued the April 26 Order, the SCAQMD's RTC program for electric generators larger than 50 MW (which was publicly traded by Cantor Fitzgerald

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[66] Rehearing Requests by Assembly, PG&E, Edison, SCWC.

[67] Rehearing Request by Williams.

[68] Rehearing Requests by Dynegy, Mirant, Reliant.

Environmental Brokerage Services) has been eliminated by the SCAQMD's governing board and the rules governing generator run-times have been altered by the Governor of California.[69] There are 35 air quality districts within California and many of these districts treat NOx emissions differently from other air quality districts within California. Moreover, the ability of these districts and the state to change the rules governing NOx emissions renders a one size fits all approach for emission costs impractical.

However, mitigation fees associated with NOx emissions are a legitimate cost of producing energy. Therefore, generators should be permitted to recover the cost of these mitigation fees. We direct the ISO to develop a specific emission allowance administrative charge assessed against all in-state load served on the ISO's transmission system in order to recover NOx emission mitigation costs assessed against generators that are required to run in accordance with ISO dispatch instructions and the must offer provisions of this order. Monies collected through this administrative charge will be placed in an interest bearing escrow account by the ISO. When a generator actually incurs mitigation costs, the generator will submit an invoice to the ISO for recovery of these costs and the ISO must pay these invoices. Because

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[69] *See* Executive Order D-40-01 by the Governor of the State of California.

all customers within California benefit from cleaner air as a result of application of these mitigation fees, the administrative charge should be assessed against all in-state load served on the ISO's system. We direct the ISO to submit tariff modifications incorporating an emission allowance administrative charge within fifteen days of the date of the order.

c. O&M Adder

The April 26 Order added $2.00 to the marginal cost price for each generator to represent operations and maintenance (O&M) expense. MID and the Assembly claim the Commission has not justified the $2.00 adder for O&M expenses. MID maintains the Commission should permit generators to include actual O&M costs.

Variable O&M costs are legitimate marginal costs that are incurred as a result of the physical production of energy. Therefore, an adder to the marginal price of energy is appropriate in order for the generating unit to recover its variable O&M costs associated with each MWh produced and bid into the ISO's imbalance energy market. The Commission found in *San Diego Gas & Electric Company, et al.*, 94 FERC ¶ 61,245 (March 9 Order), that a $2/MWh adder for variable O&M expense was reasonable. Furthermore, in the March 9 Order, we noted that the California Energy Commission also estimates variable O&M expenses of $2 to $3/MWh in a recent

report titled "Market Clearing Prices Under Alternative Resources Scenarios 2000 to 2010."[70]

We are cognizant of the concerns raised by MID that the O&M adder may be lower than actual O&M expenses; therefore, we will increase the O&M adder from $2/MWh to $6/MWh. The O&M forecasts made by the California Energy Commission are for new, efficient combined cycle units that are not the units on the margin in the California market. An O&M adder of $6/MWh is based upon a seventeen year average of actual non-fuel O&M expenses for oil and gas-fired steam plants.[71] The California market primarily consists of older oil and gas-fired steam plants. Thus, using a long-term average of actual O&M expenses for the same kind of units currently in the California market should permit generators in the California market full recovery of all non-fuel expenses.

d. Heat Rate

The April 26 Order provided that the heat rate should be based on operational heat rates and should not include start-up and minimum fuel load costs. This requirement was justified because the market clearing price should reflect the costs needed to

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[70] 94 FERC at 61,863, n. 8.

[71] *See* http:/www.eia.doe.gov/oiaf/issues/opctbl3.html. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997.

operate at or near maximum output. Williams maintains that the bid for each generator should include minimum fuel and start-up costs. It also maintains the price should be calculated each hour based on the heat rate and NOx curves for the point at which the unit is dispatched.

On May 18, 2001, the ISO submitted a status report informing the Commission that the ISO had issued two market notices to market participants providing a format for submission of the requested heat and emissions data. The ISO requested heat and emission rates for eleven different operating points with the first and last operating points representing the unit's minimum and maximum operating level, respectively. As noted by the ISO, by collecting eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range.

The ISO's proposal to include the minimum and maximum operating levels for each unit and nine points in between is reasonable. The ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams. In addition, because the ISO will have the approximate heat rate curve for each unit, the ISO is directed to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is

dispatched.[72] However, we will allow sellers to recover their actual start-up fuel costs. Sellers will invoice the ISO their actual start-up fuel costs for recovery by the ISO in the same manner that emissions costs are recovered, and the ISO must pay these invoices. We direct the ISO to submit tariff modifications incorporating these costs within 15 days of the date of this order. This change adequately reflects the concerns raised by Williams, and, therefore, its rehearing request is moot.

e. Opportunity Cost, Scarcity Rents, Recovery of Fixed Costs, and Justification of Higher Prices

Generators maintain that the Commission's methodology for calculating marginal costs excludes legitimate opportunity costs related to energy-limited plants as well as scarcity rents.[73] They further maintain that paying only marginal cost of the last unit dispatched will not provide them with a reasonable opportunity to recover the fixed costs of peaking units. They further maintain that they will be unable to recover legitimate scarcity rents.

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[72] The emissions data is no longer relevant based upon our aforementioned removal of NOx costs from the proxy market clearing price.

[73] Rehearing Requests by Avista, Duke Energy, Dynegy, Reliant, PPL.

As discussed previously, the Commission is permitting generators to fully recover their emissions costs. As the Commission explained in the April 26 Order, in the real-time market, generators do not have opportunities to sell in higher-price markets because the real-time market consists only of energy that has not been previously sold in bilateral transactions. Since the Commission is imposing similar mitigation over the United States western markets in this order, sellers would no longer have any incentive to offer energy at a higher price to any other buyers in other states. Further, by using the marginal cost of the last unit dispatched to establish the market clearing price during periods of reserve deficiency, the Commission is permitting all more efficient generators a fair opportunity to recover capital costs.

The generators maintain that, while the market clearing price will enable generators more efficient than the last generator dispatched to recover capital costs, it will not permit recovery of the capital costs for that generator. Sellers such as Avista, Duke Energy, Dynegy, Reliant, and PPL have a portfolio of generating capacity, with units that will be more efficient than the unit setting the market clearing price. Therefore, the amounts earned on the more efficient plants will cover the investment in the marginal plant. Furthermore, we note that California no longer relies exclusively on the spot market. Negotiated bilateral agreements have, in large part, replaced this market and provide opportunity for any seller to structure the arrangements necessary to

recover its costs. Finally, under the FPA and our authorization for market-based rates, sellers are not guaranteed to recover all costs but are provided the opportunity to do so.

The Commission, in this order, has sought to provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs. Sellers have not suggested a reasonable method of measuring the magnitude of such costs. The Commission's mitigation plan uses available data to develop a reasonable marginal cost for each generator and to permit reasonable recovery of legitimate costs. If sellers do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering all of their generating units in the WSCC for the duration of the mitigation plan.

Reliant and PPL contend that generators are entitled to a premium to cover the real risk of non-payment in California. We recognize that the risk of nonpayment in California continues to be greater than that in the larger West Wide market. We also note that there is a longer payment lag in the ISO spot markets of approximately 75 days that does not generally exist in the Western bilateral spot markets. We instruct the ISO to add 10 percent to the market clearing price paid to generators for all prospective

sales in its markets to reflect credit uncertainty.[74] The adder is not instituted to compensate generators for past unpaid bills. The ISO must incorporate this provision in its compliance filing. This adder may be lifted by the Commission depending on the outcome of the settlement proceeding. However, the Commission believes that questionable business practices have sent negative signals to future supplies, credit rating agencies and investors and therefore an adder for credit risk is justified and necessary.

As described above, our order today prescribes a market-driven price mitigation mechanism in all hours. Sellers dissatisfied with these prices have two options. They may propose cost-based rates for their entire portfolio of generating facilities in the WSCC in a section 205 filing with cost support including a reasonable rate of return on investment that reflects the unique conditions in California. Alternatively, although we believe the mitigated price to be adequate, sellers can seek to justify each transaction above the mitigated price. Any such justifications, however, cannot include premiums to compensate for credit risk, since our market-clearing price for the ISO's markets already reflects an adder for this risk. Similarly, a seller's emission costs cannot be used to justify exceeding the market-clearing price because our order allows each seller to recover its emission

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[74] This adder will not be reflected in the market price for the rest of the WSCC.

costs directly from the ISO. Claims of opportunity costs will not be considered because energy that is available in real-time cannot be sold elsewhere. Also, as explained elsewhere, marketers will not be allowed to justify prices higher than the mitigated prices because they must be price takers. Finally, while our approach allows recovery of gas costs, we will consider justifications based on higher actual gas costs if conditions in natural gas markets change significantly (assuming, of course, that suppliers can document and support their gas purchasing portfolio and allocation among all generating units at the relevant time).[75]

3. Applicability to Marketers And Out-of-State Generators

A number of rehearing requests contend that generators can circumvent price mitigation by selling energy to marketers.[76] They argue the generator could sell energy to a marketer at a high price and then the marketer could bid a high price into the ISO market, which it justified on the basis of its acquisition cost. In order to ensure compliance with the price

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[75] Currently, emission costs outside of California are *de minimis*. However, we recognize that this may change, and that sellers could be subject to entirely new costs resulting from changes in circumstances. We will consider such costs on a case-by-case basis.

[76] Rehearing Requests by ISO, CEOB CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

mitigation, the Commission will not permit marketers to bid a price higher than the market clearing price. This will still provide marketers with an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched and this price will be above the costs of the generators from which the marketers obtain their portfolio of energy. In this case, the marketer is no different than the last generator dispatched; it can recover the marginal costs of the last unit of energy produced.

The ISO maintains that out-of-state generators should be covered by the mitigation requirement so that any bids they submit above the market clearing price will be subject to refund. Out-of-state generators that want to have their marginal costs included in calculating the market clearing price can submit the required heat rate and gas source to the ISO for use in calculating the market clearing price. In the April 26 Order, the Commission did not require out-of-state generators to justify their price if they bid into the ISO market, because the Commission did not want to discourage out-of-state generators from bidding into the ISO market. However, now that the Commission is implementing mitigation for the entire WSCC, out-of-state generators will be treated like in-state generators.

F. Conditions on Market-Based Rate Authority

The April 26 Order conditioned public utility sellers' market-based rates to ensure that they do not engage in certain anticompetitive behavior. Sellers violating these conditions would have their market-based rates subject to refund and possible revocation.

Several generators have requested rehearing of this aspect of the April 26 Order.[77] Mirant and Williams, for example, urge the Commission to realize that sellers save certain units for when they can get the best price. Mirant contends that the bidding practices proscribed by the April 26 Order are legitimate, justifiable strategies in a competitive market and requests the Commission to eliminate the conditions or at a minimum, to limit the imposition of the conditions to certain hours.

Dynegy opposes the prohibition on the first category of bids, so-called "hockey stick" bidding. Dynegy submits that the risk of outage goes up substantially as the unit is pressed into operating longer than is advisable. The generator, therefore, faces new risks, such as a forced outage, and must be able to place premiums on the price per unit. EPSA. meanwhile, opposes the prohibition on bids that rise as the unit's output drops. EPSA states that the Commission should not revoke market-based rate authority based on a legitimate effort to recover total

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[77] Rehearing Requests by Dynegy, Mirant, Reliant, EPSA, Duke, PPL.

costs, but rather only if it finds that market power has been abused.

We will not tolerate abuse of market power or anticompetitive bidding or behavior. Emblematic of these practices is the now well-publicized bid of $3,880/MWh by Duke Energy. This bid resulted in total revenues for Duke Energy of $11 million. Exacerbating the problem was the fact that, while this transaction was identified in the March 9 Order as exceeding the proxy price, Duke Energy failed to even report this transaction in its quarterly report. The March 9 Order gave Duke Energy the choice of refunding all revenues in excess of those that would have occurred using the proxy price, or justifying the higher bid. Duke Energy chose the latter. Duke Energy argued that the payments for the energy it had supplied were in arrears, and therefore, it added a credit premium. The data show that Duke Energy's risk premium exceeds its variable cost by an order of magnitude.[78] Duke Energy's bidding at multiples of its marginal costs in an attempt to recover past due amounts can in no way be found to be just and reasonable. Accordingly, Duke Energy is directed to refund with interest pursuant to 18 C.F.R. § 35.19a,

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[78] Duke Energy unequivocally states that it is using the $3,880/MWh bid as a negotiating tool to recover payment for prior transactions. Duke Energy states that it will settle for the proxy price if and when it is paid in full for its prior, unpaid transactions. March 23, 2001 compliance filing in Docket Nos. ER01-1448-003 and ER01-1448-004 at pp. 10-12.

or offset, down to the level of the proxy price, $273/MWh for January, during the relevant hours. As the proxy price is well above Duke Energy's claimed running costs, it will be sufficient to cover any credit risk that Duke Energy may face.[79]

Public utility sellers' market based rate authority will be subject to potential revocation if they are found to have engaged in inappropriate behavior. Further, WSCC public utility sellers' market-based rate authorizations are hereby conditioned on agreeing to potential refunds for overcharges resulting from anticompetitive behavior.

The Commission denies Dynegy's request asking the Commission to clarify that the prohibition on bidding practices will expire on April 30, 2002, along with the rest of the April 26 Order.

G. Refunds

In the April 26 Order, the Commission established that all charges below the market clearing price would not be subject to refund. Refunds would be required only for sellers that fail to justify bids above the market clearing price. The Commission further stated that generators would not be

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[79] The Commission notes that there are a number of submittals dealing with sellers' market-based rate authorizations as well as bid justifications. We will address them in separate orders, if not resolved as part of the settlement process established elsewhere in this order.

liable for refunds if the Commission did not act within 60 days of the filing of the justification report.

PG&E and Edison maintain that the Commission cannot erase statutory refund obligations by stating that certain prices are deemed just and reasonable. Edison argues that the Commission must order refunds for all amounts above a just and reasonable rate and should not be able to limit refunds to emergency situations. Edison maintains that the Commission cannot establish that refund authority will expire within 60 days. It further contends that the Commission cannot shield generators from refunds, because the Commission has the authority to correct its legal errors. The CPUC maintains that refunds should exceed unlawful gains to act as a deterrent and suggests that the Commission impose treble damages, as provided for in antitrust law.

The Commission is establishing price mitigation in all hours of reserve deficiency and, as a discretionary matter, is also extending a form of that mitigation to hours of non-reserve deficiency. This price mitigation establishes the maximum just and reasonable rates in spot markets, absent cost justification. Moreover, the 60 day period for review of cost justifications was a self-imposed requirement to ensure that there is price certainty. The Commission has the authority to extend the period if necessary to finish processing the justifications.

With respect to the CPUC's arguments, the CPUC cites no provision of the FPA authorizing the

Commission to impose penalties. Finally, the Commission has no authority to impose treble damages.

H. Underscheduling Penalty

On December 15, 2000, the Commission issued an order which established, among other things, as part of a comprehensive price mitigation plan, a maximum penalty of $100/MWh if energy buyers had over 5 percent of their load served in the real-time market.[80] Several parties request that the Commission suspend the penalty for underscheduling in this proceeding.[81] Due to the Commission's decision in the April 26 Order to defer action on suspending the penalty for underscheduling, we will address this issue in a future order.

I. Confidentiality of Data

The Commission stated in the April 26 Order that it would continue the previous practice of keeping bid data confidential for six months, because disclosure of such information may lead to a reduction in competition because it will allow competitors to learn what their competitors are bidding and could lead to price collusion or coordination. The Commission also found that generator's heat rates

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[80] San Diego Gas & Electric Company, *et al.*, 93 FERC ¶ 61,294 (2000), *reh'g pending*.

[81] *See* Comments by CPUC, DWR, PG&E.

and emission cost information was also confidential business information that should not be disclosed.

Several parties contend that the Commission should not keep the heat rate and other cost information used to justify bids confidential, but should make the data publicly available, under section 205 of the FPA, on a next-day basis.[82] They also assert that due process requires that all data used to determine the proxy price is an essential part of a rate schedule and must be made available so it can be challenged by other parties, particularly ratepayers. SCWC and Assembly contend that the solution to collusion or gaming is not confidentiality, but rather regulation of seller conduct. As an alternative, San Francisco and Assembly maintain that the Commission can keep the data confidential, but that the filing of the data should be publicly noticed pursuant to the FPA, and the data should be available for review by those parties who enter into a protective order.

As the Commission found in the April 26 Order, the information on heat rates and emission costs is highly confidential business information. The disclosure of such information can cause competitive harm by allowing competitors to learn of the behavior and costs of their competitors. The Commission regulations provide for granting confidential treatment of

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[82] Rehearing Requests by NCPA, Assembly, SCWC, Edison, San Francisco, PG&E.

business sensitive information.[83] These issues are raised in other pleadings before the Commission, and we will address these matters in a later order.

EPSA's concerns relate to the independence of the ISO Board and the apprehension of disclosing confidential data to a non-independent body. EPSA suggests replacing the ISO Board or alternatively, requiring the reporting of such data to an independent entity so it can perform the marginal cost calculations. The concerns related to the independence of the ISO Board are beyond the scope of this rehearing and will be addressed in a later order.

M-S-R and TANC state that the April 26 Order is silent with respect to ordering the ISO to keep the bid and cost data confidential. While the Commission finds that the order was sufficiently clear in the first instance, out of an abundance of caution, the Commission clarifies that the ISO is ordered to treat all cost data in a confidential manner.

J. Review and Duration of the Mitigation Plan

In the April 26 Order, the Commission established a maximum one-year time period for the duration of the mitigation plan. In addition, the Commission instituted a process for reviewing the

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[83] *See* 18 C.F.R. §§ 388.112 (2000), 385.206(e), 385.213(c)(5), 385.410(c) (providing for confidential treatment for business sensitive information).

operations of the plan and the conditions in the California market on a quarterly basis.

Several parties request rehearing on the duration of the mitigation plan, stating that the Commission's decision to establish a pre-determined time period for applying mitigation is arbitrary and capricious.[84] Anaheim asserts that there is no rational basis for ending the mitigation after one year while SCWC states that the only criterion for terminating mitigation is whether markets are competitive or not. Metropolitan states that the Commission's assumptions about planned demand reduction and market development within one year should not be the basis for terminating mitigation. Metropolitan, Assembly, and others urge the Commission to monitor the progress of market entry by new generation and other market developments before termination.

The Commission is requiring the ISO to file on or before March 26, 2002, a report on market conditions that addresses among other things: (1) a list of all new generating resources (including the nameplate capacity) that the State of California has announced this year would be on line by summer 2002 and which of those facilities actually are on line (see Attachment to this order);[85] and (2) the continued progress in

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[84] Rehearing Requests by Edison, CPUC, CMUA, Anaheim, SCWC, Metropolitan.

[85] As pointed out in the April 26 Order, California has committed itself to increasing in-state generation and projects that new generation totaling 4,168 MW will be on line by the

(Continued on following page)

executing long-term contracts and reducing the reliance on the spot market. We will extend the mitigation through September 30, 2002. Our requirement for quarterly reports will continue.

K. RTO Proposal

In the April 26 Order, the Commission conditioned the implementation of the market monitoring and mitigation plan on the ISO and the three investor-owned utilities (IOUs) (SDG&E, Edison, and PG&E) filing an RTO proposal by June 1, 2001, consistent with the characteristics and functions in Order No. 2000.

Several parties have requested rehearing challenging the Commission's conditioning mitigation on the filing of an RTO.[86] While requesting rehearing on the lawfulness of the condition, City of Seattle and others assert that filing an RTO proposal by June 1, 2001 is highly unrealistic, and therefore request that the RTO condition be removed from the April 26 Order on rehearing.

As noted in the April 26 Order, the RTO condition recognizes that the only real solution to supply problems that affect the Western United States is to

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end of August 2001 and that there could be as much as 6,879 MW on line for the summer of 2002.

[86] Rehearing Requests by Seattle, Anaheim, SCWC, San Diego, CPUC, PG&E, CMUA, Metropolitan, CEOB.

create a regional response. The Commission intended to create such a response, and to improve and enhance supply and deliverability infrastructure so as to make the deliverability of supply possible and more reliable by imposing this condition as a necessary component to a solution for California and the Western United States. The ISO and two IOUs, SDG&E and Edison, filed an RTO proposal on June 1, 2001. PG&E also made a separate filing. Since the RTO filings have been made, the monitoring and mitigation plan will remain in effect. The Commission will address the adequacy of these filings in future orders. Since the ISO and utilities made the requisite filings, the requests for rehearing on this issue are moot.

L. West-Wide 206 Implementation

In the April 26 Order, the Commission instituted an investigation under section 206 of the FPA into the rates, terms and conditions of sales for resale of electric energy in interstate commerce in the WSCC other than sales through the ISO's markets, to the extent that such sales for resale involve: (1) electric energy sold in real-time spot markets (*i.e.*, up to 24 hours in advance) and (2) take place during conditions when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent. These proceedings were instituted to investigate whether and the extent to which significant increases in the prices for energy and ancillary services in the

California market are affecting prices for such services in the WSCC outside of California.

In the April 26 Order, the Commission recognized that the California market is integrated with those of other states in the WSCC. Therefore, the Commission stated its intention that, to the extent possible, its proposed changes would mirror the measures to be applied to California markets.[87] The April 26 Order proposed the following three measures for the WSCC:

> (1) A requirement that all public and non-public utility sellers, with energy operationally and contractually available in real-time, offer that energy for sale;
>
> (2) Price mitigation during periods when reserves fall below 7 percent; and
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> (3) A condition on the market based rate authority of public utility sellers selling in the WSCC region to ensure that they do not engage in anti-competitive behavior.

On April 27, 2001, the Commission issued a notice establishing a refund effective date 60 days from the date on which notice of initiation of the investigation was published in the Federal Register. The notice was published in the Federal Register, 66 Fed. Reg. 22223, on May 3, 2001. Thus, the refund effective date is July 2, 2001.

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[87] 95 FERC ¶ 61,115, at 61,356.

1. WSCC Mitigation Plan Overview

Based upon the need for uniform pricing throughout the Western region, we now find it necessary to adopt a market monitoring and mitigation plan for the WSCC spot markets. This plan will consist of several primary elements, each of which is intended to closely mirror the monitoring and mitigation plan we have adopted for California while also taking into account the various disparities between the California and WSCC markets.

Effective on the day following the date of this order, the plan we adopt below applies in all hours to all spot market transactions througnout the WSCC. In the hours when California experiences reserve deficiencies, prices for WSCC spot market sales cannot exceed the ISO's hourly market clearing price, absent justification.

Under our current and revised mitigation plan, the price in the ISO's Imbalance Market during times of insufficient operating reserves will consistently reflect the marginal cost of energy. Recent data show that during hours of sufficient operating reserves, the average hourly Imbalance Energy price has been zero and at times a negative value. These prices indicate that either there were no transactions in this market or that generation actually exceeded load during these hours. While there may be a number of factors that contribute to these anomalous results (*e.g.* changes in buying strategies), we are convinced that

we must use a modified mitigation approach during hours of non-reserve deficiencies.

For spot market sales, both in the WSCC and in California, in all non-reserve deficiency hours (*i.e.*, when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can be no higher than $119/MWh (*i.e.* 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh. For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward.

Third, the plan imposes a must-offer requirement for all hours upon sellers with the exception of hydroelectric resources and capacity needed to meet WSCC minimum operating reserve criteria for control areas. Fourth, the plan applies to all public utilities (including marketers) and non-public utilities who sell into Commission-regulated spot markets or use the interstate transmission grid subject to our jurisdiction. Market-based rate authorizations for public utilities are hereby conditioned upon adherence to this plan.

2. Interventions and Comments

In the April 26 Order, the Commission provided that comments should be submitted within ten days of the date of that order. Timely notices of intervention, motions to intervene and comments in the WSCC proceeding were filed by the entities listed in Appendix B.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, notice: of intervention and timely, unopposed motions to intervene serve to make the intervenors listed in Appendix B parties to this proceeding. Given the early stage of the proceedings, we will accept the late-filed comments.

3. Megawatt Laundering

In the April 26 Order, the Commission noted that several commenters complained that generators may

avoid the Commission's mitigation requirements through "megawatt laundering." In that order, the Commission recognized that the California market is integrated with other states and instituted the instant investigation. In addition, the Commission extended the must-offer obligation to include non-public utility generators in California which currently make use of the ISO's interstate transmission grid. In their comments, CPUC, DWR, TURN/UCAN, and CEOB request that the Commission also address megawatt laundering in this proceeding.

As discussed above, megawatt laundering will no longer be a concern due to our revised mitigation plan. First, the mitigation plan will be for all hours and will be applicable uniformly throughout the WSCC. Second, both sales within and outside California will be treated uniformly including sales by marketers. As a result of these modifications, this strategy cannot be used to avoid potential mitigation.

4. The Proposed 7 Percent Reserve Deficiency Trigger

The April 26 Order established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, and proposed that mitigation in the WSCC would be triggered when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent.

Numerous commenters raise issues regarding how the reserve deficiency mechanism would be implemented for the WSCC. Based on the numerous concerns raised by the comments, we will simplify the West-wide mitigation so that it will trigger only when the ISO declares a reserve deficiency.

5. The Proposed Must-Offer Requirement

In the April 26 Order, the Commission included a requirement that all generators in California (with the exception of hydroelectric power), including non-public utility generators that make sales through the ISO's markets or that use the ISO's interstate transmission grid, must offer any power that they have available in real time to the ISO. This includes power not already scheduled to run through bilateral agreements.[88] With respect to the WSCC investigation, the Commission stated that it intends to mirror the approach used in California.

A number of parties oppose the requirement for the WSCC. For example, the Oregon Office of Energy believes that a requirement to offer energy for sale is difficult to police because a generator must be allowed to decide when its equipment must be taken out of service and at what levels of output it can run.

We clarify that the must offer requirement throughout the WSCC will not apply to hydroelectric

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[88] 95 FERC ¶ 61,115, at 61,355-57.

resources or to generation that is necessary for control area operators to meet the applicable WSCC Minimum Operating Reserve Criteria. We recognize that outside of California there is currently no operational ISO or RTO in place in the WSCC and therefore, no centralized location to post this information. The lack of an operational regional structure will make implementation of this feature of the mitigation plan difficult.

In order to implement this feature of the mitigation plan immediately, we will require all public utilities that are control area operators to have their wholesale merchant function calculate on a daily basis the amount of capacity that will be available after load and operating reserve forecasts have been calculated. The wholesale merchant function will post this information on its company web site and on the Western System Power Pool (WSPP) web site, and will maintain in its daily log the amount of non-hydro resources that will be available. Actual arrangements for energy sales from such resources should be made with the wholesale merchant function and not with the control area operator.

To implement this requirement, we will require each marketer and independent power producing entity to post available capacity on a daily basis on its own web site and the WSPP web site.

6. Applicability to Non-public Utilities

The April 26 Order extended the must offer requirement and the price mitigation plan to non-public utility generators in California which currently make use of the ISO's interstate transmission grid or sell in the ISO's markets. The Commission found that extending these requirements to non-public utilities is necessary to ensure that the mitigation and monitoring proposal is applied equally to all generators in California.[89] Similarly, the April 26 Order proposes to extend these requirements to non-public utility generators in the WSCC.[90]

Non-public utilities oppose applying these requirements to them. On the other hand, Avista Energy requests that the Commission suspend price mitigation measures established for public utilities in the WSCC if the Commission does not extend the mitigation measures to non-public utility sellers.

For the same reasons the April 26 Order applied mitigation to all generators within California, we will extend the mitigation plan adopted herein to include all public and non-public utilities throughout the WSCC. Moreover, the percentage of non-public utility generation in the WSCC outside of California is significantly larger than that inside of California.[91]

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[89] *Id.* at 61,356.

[90] *Id.* at 61,365.

[91] *See* Powerdat database, Resource Data International, Inc., April 2001 data set.

We believe that all entities must assist with solving the problems in the WSCC. Accordingly, the Commission will require that, as a condition of selling into the markets which are subject to this Commission's exclusive jurisdiction, and as a condition of using Commission jurisdictional interstate transmission facilities, all sellers located in the WSCC, including non-public utility sellers in the WSCC, must abide by the WSCC price mitigation plan and by the must-offer obligation (if applicable) described in this order.

While the Commission does not directly regulate the non-public utility sales for resale throughout the WSCC, we have the authority, and, indeed, the responsibility, to ensure that rates, terms and conditions for jurisdictional service are just and reasonable. However, the Commission cannot ensure such just and reasonable rates in the current circumstances in the WSCC unless all entities that sell energy in the relevant spot markets or use the interstate transmission grid subject to our jurisdiction abide by the same conditions. Finally, by applying the plan discussed in this order to non-public utilities, we eliminate the incentive, and the means, for public utilities to avoid mitigation (*i.e.*, by making wholesale sales to non-public utilities for resale in the spot market).

7. Refund Issues

As noted above, the refund effective date established in this proceeding is July 2, 2001. Some

parties contend that it is premature to establish a refund effective date for the WSCC, or that the prospect of refunds could cloud supplier decision-making, while others are concerned that if a transaction is executed in the day-ahead market prior to a declared reserve deficiency, the transaction should be honored without mitigation or refund obligation.[92]

We will not rescind the refund effective date because we are legally obligated to establish a refund effective date when an investigation is instituted under section 206 of the FPA. We have established the earliest possible refund effective date permitted by the FPA Section 206, to provide maximum protection to customers. We expect that sellers will observe the requirements of this order and that the need for refunds will be rare. The commenters have not justified providing less protection. Moreover, the mitigation plan is taking effect prior to the refund effective date and this should obviate the need for refunds.

8. Mitigation Beyond Summer 2001

Although we are confident of the efficacy of our West-wide mitigation plan throughout the Summer of 2001, we nonetheless wish to obtain comment for the purpose of revising the mitigation methodology for

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[92] *See* Comments of Avista Energy, Duke and Powerex.

future periods, if necessary.[93] Accordingly, we invite interested partes to file with the Commission comments and proposals concerning: (1) any developments, either beneficial or adverse, which have occurred in the Western region spot markets as a result of this order; (2) any difficulties with implementation of the mitigation plan detailed in the order, and the relevant solutions thereto; and, most importantly (3) any alternative market mitigation approaches. In order to provide for timely review and analysis, we will require that parties' comments and proposals be submitted to the Commission within 60 days of the date of issuance of this order.

M. Settlement Conference

We will require that all public utility sellers and buyers in the ISO's markets participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future. To achieve this goal, it is imperative that the parties reach agreement on (1) the additional load that is to be moved from the spot market to longer-term contracts, (2) refund (offset) issues related to past periods, and (3) creditworthiness matters. In highlighting these specific issues, we are not suggesting that the settlement discussions

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[93] In particular, we seek comments on whether our approach is appropriate given regional differences between California and other regions.

are limited to these matters, but emphasize that all issues that remain outstanding to resolve past accounts and ensure California's energy future are on the table for the parties to address. Finally, we stress that it will be critical to the success of these discussions that the State of California designate one or more representatives, authorized to act on behalf of all affected state interests, to participate fully in the settlement discussions. We will appoint the Chief Administrative Law Judge or his designee to serve as a settlement judge to assist the parties in reaching a settlement and require the judge to convene an initial settlement conference no later than June 25, 2001, and to complete the settlement discussions no later than 15 days after the commencement of the settlement conference. The settlement judge shall make a recommendation to the Commission within 7 days after the close of the settlement discussions if the issues are not resolved by the parties.

N. ISO Compliance Filing

In the April 26 Order, the Commission directed the ISO to submit a compliance filing no later than fifteen days from the date of that order. The ISO made its compliance filing in Docket Nos. EL00-95-034 and EL00-98-033 on May 11, 2001. Due to the significant modifications to the mitigation plan we are adopting today, we will require a new compliance filing within 15 days of the date of this order.

The Commission orders:

(A) The ISO shall submit tariff changes to comply with this order within 15 days of the date of this order.

(B) Sellers of energy in the WSCC are subject to the mitigation plan as discussed in the body of this order. The mitigation plan will become effective on the day following the date of this order.

(C) Rehearing is granted in part, and denied in part, as discussed in the body of this order.

(D) The requests for stays of the April 26 Order are denied as discussed in the body of the order.

(E) No later than 7 days after the completion of settlement discussions, the settlement judge shall make a recommendation to the Commission with respect to the settlement negotiations in the captioned dockets.

(F) Duke Energy must file a report quantifying refunds or offsets within 15 days of the date of this order, as discussed in the body of this order.

(G) Interested parties are hereby invited to file comments and proposals regarding the market mitigation plan, as discussed in the body of this order.

By the Commission. Commissioner Massey concurred in part with a separate statement attached.

(SEAL) Commissioner Breathitt concurred with a separate statement attached.

/s/ Linwood A. Watson, Jr.
Linwood A. Watson, Jr.,
Acting Secretary.

Appendix A
Requests for Rehearing of April 26 Order
(* – denotes request for late intervention)

Party	Abbreviation
American Public Power Association	APPA
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
California Air Resources Board*	ARB
California Department of Water Resources	DWR
California Electricity Oversight Board	CEOB
California Independent System Operator Corporation	ISO

California Municipal Utility Association	CMUA
California State Assembly	Assembly
Calpine Corporation	Calpine
Cities of Anaheim, *et al.*	Anaheim
City and County of San Francisco	San Francisco
City of Burbank*	Burbank
City of San Diego	San Diego
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition[94]	CAC/EPUC
Consumer Federation of America*	CFA
Duke Energy North America, *et al.*, LLC	Duke Energy
Dynegy Power Marketing, Inc. *et al.*	Dynegy
Electric Power Supply Association	EPSA
Imperial Irrigation District*	IID
Los Angeles Department of Water and Power	LADWP

[94] Request for stay.

M-S-R Public Power Agency, *et al.*	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, *et al.*	Mirant
Modesto Irrigation District	MID
National Rural Electric Cooperative Association*	NRECA
Northern California Power Agency	NCPA
Pacific Gas and Electric Company	PG&E
PPL EnergyPlus, LLC, *et al.*	PPL
Public Utilities Commission of State of California	CPUC
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
San Diego Gas & Electric Co.	SDG&E
South Coast Air Quality Management District*	SCAQMD
Southern California Edison Company	Edison

Southern California Water Company	SCWC
Transmission Agency of Northern California	TANC
Turlock Irrigation District*	TID
Williams Energy Marketing & Trading Company	Williams

Appendix B
WSCC Comments
(* – denotes Motions to Intervene)
(** – denotes Notice of Intervention)
(*** – denotes late filed comments)

Party	Abbreviation
AES Southland, Inc.***	AES
American Public Power Association*	APPA
Attorney General of Washington*	Washington Attorney General
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
Avista Utilities	Avista Utilities
California Air Resources Board*	ARB
California Department of Water Resources*	DWR

California Electricity Oversight Board***	CEOB
California Independent System Operator Corporation	ISO
California Municipal Utility Association	CMUA
California State Assembly	Assembly
Cities of Anaheim, *et al.**	Anaheim
County of San Diego*	San Diego
City and County of San Francisco*	San Francisco
City of Burbank*	Burbank
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition*	CAC/EPUC
Cogeneration Coalition of Washington*	CCW
Colorado Association of Municipal Utilities*	Colorado AMPS
Duke Energy North America, *et al.*, LLC*	Duke Energy
Electric Power Supply Association	EPSA
Enron Power Marketing, Inc. and Coral Power, L.L.C.	Enron

Idaho Public Utilities Commission**	Idaho Commission
Imperial Irrigation District*	IID
Los Angeles Department of Water and Power***	LADWP
M-S-R Public Power Agency, *et al.*	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, *et al.**	Mirant
Modesto Irrigation District*	MID
Morgan Stanley Capital Group Inc.	Morgan Stanley
National Rural Electric Cooperative Association*	NRECA
Nevada Attorney General's Bureau of Consumer Protection*	Nevada BCP
Nevada Independent Energy Coalition*	NIEC
Nevada Public Utilities Commission*	Nevada Commission
Northern California Power Agency	NCPA
NRG Power Marketing Inc.	NRG

Official Committee of Unsecured Creditors of PG&E*	OSC
Oregon Office of Energy	Oregon Office of Energy
Pacific Gas and Electric Company*	PG&E
Pinnacle West Capital Corporation, Arizona Public Service Company, Pinnacle West Energy Corporation and APS Energy Services, Inc.	Pinnacle West Companies
Portland General Electric Company	PGE
Powerex Corporation*	Powerex
PPL EnergyPlus, LLC, *et al.**	PPL
Public Utilities Commission of State of California**	CPUC
Puget Sound Energy, Inc.*	Puget Sound
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
Salt River Project Agricultural Improvement and Power District*	SRP
San Diego Gas & Electric Co.****	SDG&E

South Coast Air Quality Management District*	SCAQMD
Southern California Edison Company*	Edison
Tri-State Generation and Transmission Association, Inc.*	Tri-State
Turlock Irrigation District*	Turlock
Utah Municipal Power Agency*	UMPA
Utility Reform Network and the Utility Consumers' Action Network	TURN/UCAN
Washington Utilities and Transportation Commission**	Washington Commission
Williams Energy Marketing &Trading Company	Williams
Wyoming Public Service Commission***	Wyoming Commission

MASSEY, Commissioner, *concurring in part*:

Today's order brings expanded price restraints mitigation to a broken market. I support the order because it adopts measures that I have been championing for the past eight months. Price controls are now extended to the entire western interconnection, thereby eliminating the "megawatt laundering" problem that has vexed the mitigation programs

adopted by the Commission and the ISO over the past year. Cost-based price constraints are now extended to all hours, not just those of reserve deficiency. We have long needed 24 x 7 coverage, and now we finally have it. The price caps will remain in place until September 2002, giving the market two full summers to correct. I endorse these measures.

While better late than never, I wish this Commission had taken effective action sooner. Until today, the Commission had stubbornly refused to implement full time price constraints, despite rather clear evidence that prices were not just and reasonable. We could have prevented much of the economic carnage in the western interconnection that has occurred over the past year.

Given that the Commission today adopts measures that I have long advocated, I am tempted to declare victory and let it be. But I cannot. There are some aspects of the order that I have reservations about, and for these reasons I concur with the order. One aspect is the addition of a 10 percent surcharge to the market clearing price to reflect credit uncertainty. I do not see the need for this. The Commission has issued orders in the past few months instructing the ISO to abide by the creditworthiness requirements of its tariff. I am concerned that the adder may diminish the ISO's enforcement of those requirements. Moreover, it is my understanding that recently all sales into the ISO's markets have been backed by a creditworthy party. Instituting this surcharge does have a modest bright side, however.

Generators may no longer attempt to justify bids on the basis of credit risk above what is provided for in the cost based clearing pricing methodology. This was a major flaw of the old ineffective $150 benchmark in our earlier mitigation program. Eliminating that ground for high prices is a positive development.

Second, the order should have provided guidance to the parties that will participate in the settlement conference we order. I believe we are avoiding our responsibility under the Federal Power Act to set just and reasonable prices by requiring parties to settle a multitude of issues with a price tag in the billions of dollars without at least two cents worth of guidance.

And finally, I do not agree with the rhetoric in this order that characterizes cost of service pricing as irrelevant, and perhaps even downright harmful, on the theory that it would discourage new supply. I do not understand the need nor the logic of this language. We have made a choice in this order to strike a balance between strict cost of service regulation and blind reliance on the market. The mitigation program puts in place important cost based price caps while relying on market based pricing. The order sets out reasons for this balanced choice, and articulating them is all that is needed to support our decision. I strongly disagree with the statement in the order that "a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty" under the Federal Power Act. I do not read the Federal Power Act, and the relevant court decisions, so restrictively. There is still

an important role for cost of service regulation where markets are not adequate.

What is curious about this aspect of the order is that the concern is to avoid discouraging new supply. However, as the well respected economist Alfred Kahn recently said of our long reliance on cost of service regulation, "(i)f the literature agrees on anything about that experience, it is that cost-based regulation, as traditionally practiced, has encouraged the goldplating of service and the very excess capacity that seemed to promise such enormous benefits to consumers during the past decade if rates were deregulated."[1] Dr. Kahn believes that cost of service may lead to too much supply. Thus, I do not understand the majority's logic concerning cost-based regulation and supply adequacy.

These concerns notwithstanding, I support today's order and the price protection plan it puts in place. To ensure that this price protection plan is successful, the Commission must exercise all of its statutory powers to keep natural gas prices in the West at just and reasonable levels. It is probably generally true that the marginal plant dispatched in California is fired by natural gas and uses a lot of it. Thus, the success of the plan we adopt today in lowering prices depends in large part on fluctuations

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[1] Statement of Alfred E. Kahn before the Committee on Governmental Affairs, United States Senate, June 13, 2001 at page 3.

in the price of natural gas. The Commission continues to have work to do in ensuring just and reasonable gas prices.

Today's price protection plan gives California and the West breathing room while their electricity markets are brought back to health. A number of items need to be addressed in the next 15 months for the recuperation to be successful. Clearly, there must be substantial amounts of new generation capacity brought on line. A more balanced supply portfolio must be developed as California moves away from an over reliance on the spot markets. A robust demand response program must be implemented through demand bidding and accurate price signals. Transmission constraints must be relieved in some way. And finally, the California ISO should explore a number of market reforms, such as the adoption of security constrained unit commitment dispatch, the creation of an installed capacity market and reserve requirements, and a single integrated day-ahead market. Without these measures, I would be concerned about whether the markets in the West can be brought back to health.

For these reasons, I concur with today's order.

/s/ William L. Massey
William L. Massey
Commissioner

Breathitt, Commissioner, *concurring*;

I concur with the result of today's order, and write separately to highlight one aspect of it. I am concerned about the imposition of a ten percent surcharge on the market clearing price paid to generators to reflect credit uncertainty in California. I have two primary concerns. First, the imposition of such a credit surcharge seems to concede to the California Independent System Operator (ISO) the issue of whether or not the ISO must implement the Commission's creditworthiness standards. We have directed the ISO to ensure the presence of a creditworthy counterparty for certain transactions.[1] I am not ready to concede this issue and, therefore, I call upon the ISO immediately to implement our orders regarding creditworthiness.

Second, I believe the imposition of such a credit surcharge may be premature. In today's order we also initiate settlement discussions among all public utility sellers and buyers in the ISO markets. Among the issues we direct the parties to consider in their negotiations are "creditworthiness matters." I am concerned that the credit surcharge could adversely affect the settlement discussions on the issue of prospective credit uncertainty.

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[1] California Independent System Operator Corporation, *et al.*, 95 FERC ¶ 61,026, at 61,081 (2001)

Otherwise, I agree with my colleagues that creditworthiness and non-payment of accounts are serious problems in California. I believe the Commission and the ISO must take immeditate steps to address these problems. I just hope this surcharge does not prove to be an inappropriate remedy for this problem. Therefore, I respectfully concur.

/s/ Linda K. Breathitt
Linda K. Breathitt
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

101 FERC § 61,304

Before Commissioners:
Pat Wood III, Chairman;
William L. Massey, and
Nora Mead Brownell.

Puget Sound Energy, Inc., *et al.* Complainant,	)	
v.	)	
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Respondents.	)	Docket Nos. EL01-10-000 EL01-10-001

ORDER ON MOTIONS TO
REOPEN EVIDENTIARY RECORD

(Issued December 19, 2002)

1. In this order, we grant in part and deny in part motions seeking to reopen the evidentiary record in the EL01-10, *et al.* docket for the purpose of allowing parties to submit additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001. In taking this action, our goal is to provide all parties an opportunity to ensure that all relevant evidence is

adduced in this proceeding, but also to bring closure and certainty to this proceeding (to sellers and customers alike) fairly and quickly.

I. Background

2. On October 26, 2000, Puget Sound Energy, Inc. (Puget Sound) filed a complaint alleging that spot market prices in the Pacific Northwest were unjust and unreasonable. In a December 15, 2000 order (December 15 Order),[1] the Commission declined to implement a region-wide price cap, as Puget Sound had requested. Puget Sound and others timely sought rehearing of the December 15 Order's determination not to impose a regional price cap or other mitigation. However, on June 22, 2001, Puget Sound filed a motion to dismiss its complaint and its subsequent rehearing request. Instead, in a July 25, 2001 order (July 25 Order)[2], the Commission established a preliminary evidentiary hearing pertaining to the Northwest for the period beginning December 25, 2000 through June 20, 2001 to help facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest. In the July 25 Order, the Commission also stated that it would

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[1] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, *et al.*, 93 FERC ¶ 61,294 (2000), *reh'g denied*, 97 FERC ¶ 61,275 (2001).

[2] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, *et al.*, 96 FERC ¶ 61,120 (2001).

decide at a later time whether to allow Puget Sound to withdraw the complaint. On September 24, 2001, the Presiding Administrative Law Judge (ALJ) issued recommendations and proposed findings of fact in the case, finding no basis to order refunds.[3]

Motions

3. On May 13, 2002, the City of Tacoma, Washington (Tacoma) filed a motion in which it requests that the Commission reopen the evidentiary record in the EL01-10, *et al.* docket to allow a "hearing on all issues related to refunds for wholesale energy transactions in excess of the market clearing price in the Pacific Northwest" and permit further investigation and discovery into the actions of specific participants in the Pacific Northwest power market. Tacoma states that since the issuance of *Puget Sound,* material evidence has become available that demonstrates that the Presiding Judge's conclusions in that decision are "clearly erroneous." On September 9, 2002 and October 2, 2002, Tacoma filed supplements to its motion in which it identifies the existence of additional evidence it alleges is material and relevant to this proceeding.

4. In its motion, Tacoma identifies multiple grounds for reopening the evidentiary record in Docket No. EL01-10, *et al.* Among those are: (1) the release of

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[3] *See* Puget Sound Energy Company v. Sellers of Energy and Ancillary Services, 96 FERC ¶ 63,044 (2001) (*Puget Sound*).

documents obtained as part of the Staff investigation in Docket No. PA02-2-000; (2) the issuance of the Commission Staff's initial report in that docket, (3) the initiation of separate proceedings to investigate instances of possible misconduct of the companies named in those proceedings, which are also respondents in the EL01-10, *et al* docket; and (4) the Commission solicitation of comments on whether the Commission should change the method for determining refunds in the California refund proceedings. Tacoma also argues that the expedited nature of the proceedings that the Commission ordered contributed to material evidence being unavailable to the Presiding Judge in the EL01-10, *et al.* docket hearing. Tacoma also adds that the recommendations of the Presiding Judge in this proceeding are inconsistent with the determination the Commission made in Docket No. EL02-28, *et al.*,[4] setting for hearing the issue of whether the dysfunctional California spot markets adversely affected the long-term bilateral markets. Tacoma concludes that its motion and supplements thereto provide sufficient evidence to warrant further investigation and discovery into the actions of Pacific Northwest market participants.

5. On May 24, 2002, the City of Seattle, Washington (Seattle) filed a motion requesting that it be allowed to supplement the record or, alternatively, that the

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[4] Nevada Power Co. and Sierra Pacific Power Co. v. Duke Energy Trading and Mktg, L.P., *et al.*, 99 FERC 61,047, *order on reh'g* 100 FERC ¶ 61,273 (2002), *reh'g pending*.

Commission reopen the evidentiary record to allow for a hearing before the Presiding Judge. On June 24, 2002, Public Utility District No. 1 of Grays Harbor County, Washington (Grays Harbor) also filed a motion in this proceeding, requesting that the Commission reopen the evidentiary record. In particular, Seattle and Grays Harbor seek to supplement the evidentiary record with evidence developed in the PA02-2-000 Staff investigation and related proceedings.

Answers In Support

6. California Parties[5] and Attorney General of Washington (Washington AG) support Tacoma's motion. In their opinion, the reasons offered by Tacoma for reopening the evidentiary record are compelling. In particular, Washington AG argues that the Presiding Judge's recommendations are undermined by evidence obtained in Docket PA02-2-000 and that Pacific Northwest utilities should be treated equally with the utilities that have claimed refunds in the EL00-95, *et al.* docket proceeding. Washington Utilities and Transportation Commission, the Oregon Office of Energy, and the Oregon Public Utilities Commission (jointly, Washington Commission) do not oppose Tacoma's motion but urge the Commission to reopen the

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[5] California Parties include the People of the State of California, *ex rel.* Bill Lockyer, Attorney General, and the California Electricity Oversight Board.

evidentiary record only for the purpose of investigating the facts and consequences of market manipulation and to focus its remedies, if any, only on wrongdoers. The Washington Commission would oppose imposition of refunds based on spot market transactions.

Answers in Opposition

7. Puget Sound argues that the evidentiary record should not be reopened because the overwhelming majority of market participants, including public power entities, opposed initiation of a wholesale refund proceeding in these dockets in the first place. The Indicated Marketers,[6] Transaction Finality Group (TFG),[7] and Mirant argue that the movants have failed to demonstrate the extraordinary circumstances necessary to reopen the evidentiary record

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[6] The Indicated Marketers include Mirant Americas Energy Marketing, L.P. (Mirant); TransAlta Energy Marketing (U.S.) Inc.; and Morgan Stanley Capital Group Inc.

[7] The TFG is composed of Alcoa, Inc.; Avista Energy, Inc.; Columbia Falls Aluminum Company, LLC; Coral Power, LLC; Duke Energy Trading and Marketing, L.L.C.; Edison Mission Marketing & Trading, Inc.; Exelon Corporation on behalf of Exelon Generation Company, LLC; PECO Energy Company and Commonwealth Edison Company; IDACORP Energy, L.P.; Pinnacle West Capital Corporation/Arizona Public Service Company; Portland General Electric Company; PPL Montana, LLC and PPL Energy Plus, LLC; Public Service Company of Colorado; Public Service Company of New Mexico; Puget Sound Energy, Inc.; Trans Canada Energy Ltd.; BP Energy Company; Powerex Corp.; and Sempra Energy Trading Corp. Powerex Corp supports and supplements the comments filed by the TFG.

in this proceeding, as required by Commission precedent.[8] Similarly, TransCanada Energy Ltd. (TransCanada) asserts that Tacoma's motion fails to provide appropriate justification for its request. In TFG's and Indicated Marketers' opinion, the movants should also have established a logical or factual nexus between alleged market manipulation in the California Independent System Operator and California Power Exchange markets and alleged dysfunctions in the Pacific Northwest markets. Eugene Water and Electric Board, Coral Power (Coral), and TFG argue that there is no purpose to reopening the *Puget Sound* docket prior to the completion of the Staff investigation in the PA02-2-000 docket. TFG believes that a different approach would create uncertainty.

Procedural Matters

8. On June 3, 2002, the Bonneville Power Administration (BPA) filed an untimely answer to Tacoma's May 13, 2002 motion. On June 7, 2002, Tacoma filed a motion to strike BPA's untimely answer. We will disallow BPA's answer pursuant to Rule 213(d) of the

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[8] The Indicated Marketers cite to Systems Energy Resources, Inc., 96 FERC ¶ 61,165, at 61, 736 (2001) (holding that the Commission's "general rule is that 'the record once closed will not be reopened' absent a demonstration that extraordinary circumstances outweigh the need for administrative finality."); CMS Midland, Inc., *et al.*, 56 FERC ¶ 61,361, 61,736 (1991) (stating that the requesting "party must demonstrate a change in circumstances that is more than just material – it must be a change that goes to the very heart of the case.").

Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(d) (2002).

9. On August 7, 2002, Grays Harbor filed an answer to the Indicated Marketers' answer. Answers to answers are generally not permitted pursuant to Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2002), unless otherwise permitted by the decisional authority. We are not persuaded to allow Grays Harbor's answer to the Indicated Marketers' answer.

Discussion

10. In their motions, Tacoma, Seattle, and Grays Harbor seek to reopen or, in the alternative, supplement, the evidentiary record in Docket No. EL01-10, *et al.* In particular, Tacoma requests permission to introduce evidence developed in the PA02-2-000 docket and related proceedings and to conduct further investigation and discovery into the actions of Pacific Northwest market participants.

11. We will allow the movants and other parties in this proceeding to conduct additional discovery for the period January 1, 2000 to June 20, 2001. This may include depositions, data requests, and any other appropriate form of discovery. Parties should not duplicate the discovery conducted in other Commission proceedings, but may submit evidence from those proceedings in their filings in this proceeding, to the extent relevant. We direct the Chief Administrative Law Judge to appoint an ALJ as a Discovery Master

to resolve any discovery-related disputes that may arise. To prevent disclosure of confidential information, the presiding judge may adopt a protective order, as appropriate.[9]

12. All of the parties will have until February 28, 2003 to submit directly to the Commission additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001 and proposed new and/or modified findings of fact. Parties must provide relevant documents and citations to the record to support any proposed substantive recommendations.

13. We intend to finalize the issues in this docket expeditiously. For this reason, we are not remanding this case to the Presiding Judge and will review additional evidence along with the Presiding Judge's recommendations in *Puget Sound*. Therefore, Tacoma's, Seattle's and Grays Harbor's motions are hereby granted in part and denied in part.

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[9] The Commission and its Staff conducting the investigation in Docket No. PA2-2-000 will not be subject to discovery and the parties may not conduct depositions of and/or request information from the Commission or its Staff, as it would interfere with the Staff investigation in Docket No. PA02-2-000. The Commission's Litigation Staff shall not conduct discovery or otherwise participate in this phase of this proceeding.

The Commission orders:

(A) Tacoma's, Seattle's and Grays Harbor's motions are hereby granted in part and denied in part, as discussed in the body of this order.

(B) No later than February 28, 2003, the parties in this proceeding shall submit directly to the Commission additional evidence and proposed new and/or modified findings of fact with specific citations to the record to support any proposed substantive recommendations.

(C) The Chief Administrative Law Judge is hereby directed and authorized to appoint an Administrative Law Judge as a Discovery Master within ten days (10) of the date of issuance of this order. The Discovery Master shall administer discovery and resolve any potential discovery disputes.

By the Commission. Commissioner Brownell dissenting with a separate statement attached.

(SEAL)

Linwood A. Watson, Jr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. *et al.*	)	
	)	
v.	)	
	)	
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement	)	Docket Nos. EL01-10-000 EL01-10-001

(Issued December 19, 2002)

BROWNELL, Commissioner, *dissenting*

In today's order the majority re-opens the record in a case in which a Presiding Administrative Law Judge has already completed a hearing and issued Recommendations and Proposed Findings of Fact; and in which the complainant has moved to withdraw its complaint. Neither equity nor efficiency is served by re-opening the record in this proceeding.

Nora Mead Brownell
Commissioner

Supreme Court, U.S.
FILED
DEC 16 2009
OFFICE OF THE CLERK

No. 09-288

IN THE
Supreme Court of the United States

PUGET SOUND ENERGY, INC., AVISTA CORPORATION, AVISTA ENERGY, INC., CONSTELLATION ENERGY COMMODITIES GROUP, INC., IDACORP ENERGY L.P., MORGAN STANLEY CAPITAL GROUP INC., PORTLAND GENERAL ELECTRIC COMPANY, POWEREX CORP., SEMPRA ENERGY TRADING LLC, SHELL ENERGY NORTH AMERICA (US), L.P., AND TRANSCANADA ENERGY LTD.,
Petitioners,

v.

PEOPLE OF THE STATE OF CALIFORNIA, ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Ninth Circuit

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CORPORATE DISCLOSURE STATEMENTS

Petitioners' Statements pursuant to Rule 29.6 were set forth at pages v-x of the petition for a writ of certiorari, and there are no amendments to those Statements.

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I. THE NINTH CIRCUIT'S HOLDING THAT FERC'S ACTIONS IN THIS CASE ARE REVIEWABLE WARRANTS THIS COURT'S REVIEW

In *Heckler v. Chaney*, 470 U.S. 821 (1985), this Court held that "an agency's decision not to take enforcement action" is "presumptively unreviewable." *Id.* at 832; *see* 5 U.S.C. § 701(a)(2). None of the respondents here defends the Ninth Circuit's broad holding that a non-enforcement decision *is* reviewable whenever the agency "take[s] steps towards enforcing a violation of the law" or "commit[s] resources to an examination of whether" enforcement is "warranted." Pet. App. 18a. Nor does any respondent deny that this novel standard conflicts with the standard numerous other courts of appeals apply.

The Government nevertheless contends that the specific procedures FERC employed to inform its decision not to enforce § 206 make that decision not to act reviewable, notwithstanding FERC's contrary position when it elected to use those procedures and in arguing to the court below. The Government's current position only deepens the existing confusion over when agencies may invoke and courts should apply *Heckler*, which rests not on *how* the agency chooses to inform its exercise of discretion, but on *whether* the decision is committed to the agency's discretion by law. As at least four courts of appeals have held, *Heckler* does not turn on the procedures an agency employs in reaching a decision not to enforce.

1. FERC's orders at issue here undisputedly reflected FERC's decision not to initiate its own, prosecutorial enforcement action under § 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e. As the Government concedes, "[i]n July 2001, acting on its own initiative, [FERC] instituted a separate proceed-

ing to consider past spot-market sales in the Pacific Northwest," but "[FERC] did not invoke 16 U.S.C. 824e to determine whether to change the rates on file." Gov't Br. 4. Indeed, FERC expressly declined to decide whether the rates were unreasonable. *See* Pet. App. 392a-393a. Such a determination lies at the core of FERC's authority under § 206; therefore, FERC could not have exercised its ancillary power to order refunds "in excess" of the just-and-reasonable rate without first "institut[ing] a proceeding" to determine the just-and-reasonable rate. 16 U.S.C. § 824e(b). In its orders here, FERC thus accurately characterized its action as a "decision not to enforce," expressly invoking *Heckler* to support its inaction. Pet. App. 402a n.64.

The Government – reversing FERC's position in its orders and in the court below – now implausibly asserts that FERC resolved claims that buyers in the PNW were entitled to refunds as though FERC had conducted and completed a formal § 206 proceeding to determine whether prices were unjust or unreasonable. *See* Gov't Br. 10; *accord* Resp. Br. 16.[1] Such a ruling would have been unlawful because FERC did not comply with the statutory requirements of § 206. *See* Law Profs. Br. 7. Following FERC's "review of [its own] motion," FERC did not "fix by order the time and place" of a § 206 hearing, "specify the issues to be adjudicated," or "establish a refund effective date." 16 U.S.C. § 824e(a), (b). Indeed, FERC consistently and expressly declined to set a hearing pursuant to § 206. *See* Pet. App. 102a-103a, 382a, 417a, 424a. Instead, FERC explained its decision *not*

[1] None of the cases respondents or the court below cite as examples of courts reviewing FERC's refund decisions involved a FERC decision not to initiate a § 206 proceeding. *See* Pet. App. 19a; Gov't Br. 10; Resp. Br. 17 n.6.

to undertake an enforcement proceeding. That decision was a classic exercise of FERC's prosecutorial discretion, based on FERC's conclusion that it was not possible to achieve "an equitable resolution of the matter" even if a subsequent § 206 proceeding were to find the rates in question to be unjust or unreasonable, *id.* at 401a-402a, and that "[t]he time and resources" required even to attempt such a resolution could not be justified by the likelihood of success, *id.* at 442a.

The non-federal respondents attempt to draw a line between FERC's "investigations" and its "adjudications." *See* Resp. Br. 14 & n.5, 16, 21 n.8. But nothing in the form of FERC's proceedings here suggests FERC was rendering a decision on the merits under § 206. As FERC itself explained, the preliminary evidentiary proceeding was to gather "additional information before making a decision" whether to proceed to enforcement, Pet. App. 425a, and to "assist[] [FERC] in understanding the Pacific Northwest spot market and the proper action to be taken," *id.* at 390a. Contrary to the non-federal respondents' suggestion (at 16), the fact that the agency provided participants with what it characterized as "additional as well as unusual process to determine whether the proceeding should continue" (Pet. App. 417a) does not change the nature of FERC's decision.

2. Respondents thus focus on the manner in which FERC informed its exercise of discretion. *See* Gov't Br. 9-10; Resp. Br. 14-15. Although both respondents' briefs chronicle the nature of FERC's proceedings below, neither offers an argument why FERC's use of *any* particular procedure subjects to judicial review the otherwise discretionary decision not to enforce § 206. The Government states only that FERC's proceeding "had much in common with

adjudicatory proceedings that usually are subject to judicial review." Gov't Br. 10; *see* Resp. Br. 16-17.

As petitioners explained – in analysis that neither respondents' brief challenges – respondents' position finds no support in *Heckler*. *See* Pet. 17-18. This Court has held that an agency's decision not to exercise its enforcement authority is reviewable only if "meaningful standards" exist "for defining the limits of [the agency's] discretion." *Heckler*, 470 U.S. at 834-35. Whether a court has "law to apply" (*id.* at 834) in reviewing an agency's exercise of enforcement discretion does not depend on the procedures an agency utilizes to inform that discretion. Respondents offer no standard for determining the circumstances in which FERC must act on its own motion to enforce § 206.[2]

Proceeding from the mistaken (and unsupported) premise that FERC's use of a public hearing to inform its discretion whether to launch a § 206 enforcement proceeding is a reviewable "adjudication" regardless of whether there is law to apply, respondents deny any conflict between this case and those in which other circuits have held that an agency's choice of procedure does not subject to judicial review its discretionary decision not to enforce. Respondents argue that the latter cases did not "involve[] the kind of formal adversarial proceedings at issue here," Gov't Br. 11, or "entail[] an adversary proceeding of the kind FERC conducted here," Resp. Br. 18. But the Ninth Circuit departed from other circuits'

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[2] Contrary to the non-federal respondents argument (at 20 n.7), the "just and reasonable" standard of § 206 did not furnish "law to apply" because FERC never addressed the reasonableness of the rates. *See* Pet. App. 424a. The ALJ's recommendations on that point, moreover, did not constitute final agency action; FERC did not adopt them.

correct implementation of *Heckler* by holding that *any* choice of procedure could subject an agency's decision to review. *See* Pet. App. 18a-19a.

In *Greer v. Chao*, 492 F.3d 962 (8th Cir. 2007), by contrast, the Eighth Circuit held that "the manner in which an agency opts to investigate a complaint is largely a matter left to the agency's discretion." *Id.* at 965. Similarly, the D.C. Circuit consistently has held that an agency's use of pre-enforcement procedures, such as a "show cause" order and subsequent proceedings, does not overcome the presumption against review of decisions not to enforce absent some contrary indication in the substantive statute. *New York State Dep't of Law v. FCC*, 984 F.2d 1209, 1215 (D.C. Cir. 1993); *see Baltimore Gas & Elec. Co. v. FERC*, 252 F.3d 456, 460 (D.C. Cir. 2001) (holding decision not to enforce following four-year "formal" investigation unreviewable because Natural Gas Act "lacks guidelines against which to measure FERC's exercise of its discretion"). Other cases are in accord. *See Sierra Club v. Larson*, 882 F.2d 128, 132 (4th Cir. 1989); *Sherman v. Black*, 315 F. App'x 347, 349 (2d Cir. 2009).

Under the law in those four circuits, this case would have been decided on the FPA's text alone, and FERC's decision not to enforce § 206 would have been held unreviewable because that statute does not constrain FERC's discretion to undertake enforcement actions on its own motion. *See* Pet. 19-20. Respondents advance no contrary argument.

3. The Ninth Circuit's decision will imperil well-informed agency decisionmaking by creating "skewed incentives" for agencies *not* to collect information prior to deciding whether to enforce a statute. Law Profs. Br. 11. Agencies will face a choice between justifying decisions not to enforce with enough detail

to withstand judicial review and eschewing any public "steps" to gather information, lest they subject their non-enforcement decisions to such review. And the decision below threatens targets of agency investigations with legal jeopardy long after the agency has chosen not to take action.

Contrary to the non-federal respondents' argument (at 19-20), such confusion results whether the Ninth Circuit's opinion is given a broad or a narrow reading. The Government's brief here well demonstrates that confusion. The Government declines to defend the Ninth Circuit's bright-line test, instead arguing that it is consistent with *Heckler* for a court to review any agency "adjudicatory proceeding," Gov't Br. 9; "trial-type evidentiary hearing[]," *id.* at 9-10; "public, trial-type fact-finding proceeding," *id.* at 11; or "formal adversarial proceeding[]," *id.* The Government does not define any of those formulations in the context of pre-enforcement agency action. Yet federal agencies have invoked *Heckler* in a wide variety of circumstances in recent or pending cases upon which the Government now casts suspicion (without explaining how other agencies should act). *See, e.g.*, Brief of Appellees at 18-19, *Heide v. Scovel*, No. 09-1173 (8th Cir. filed Apr. 22, 2009) (arguing that Department of Transportation decision not to enforce following investigation and report by its Inspector General was unreviewable, citing *Greer*); Final Brief for Respondents at 28, 41-42, *Sierra Club v. EPA*, 557 F.3d 401 (6th Cir. 2009) (No. 07-4485) (arguing that Environmental Protection Agency denial of petition relating to permitting was "functional[ly] similar[]" to exercise of prosecutorial discretion and that judicial review would "render[] illusory the repose and finality" of agency action); Gov't Defs.' Opp. to Pls.' Mot. for Summ. J. at 10, *King v. Office for Civil Rights*, 573 F.

Supp. 2d 425 (D. Mass. 2008) (Civ. A. No. 07-10861-PBS) (arguing that agency decision to terminate investigation was unreviewable because "OCR's exercise of judgment about what information is necessary to determine whether [to enforce] is within OCR's discretion"). The Ninth Circuit's decision – and the Government's gloss on that decision – creates significant uncertainty for all federal agencies, which now do not know whether to follow their existing pre-enforcement practices or the vague direction offered in the Government's brief. This Court should grant certiorari to resolve that confusion.

II. THE NINTH CIRCUIT'S RULINGS ON THE SCOPE OF FERC'S PROCEEDINGS WARRANT FURTHER REVIEW

The Government agrees that the Ninth Circuit erred in interfering with FERC's discretion to structure its own proceedings (Question Presented No. 2) and in overturning FERC's interpretation of the Puget complaint (Question Presented No. 3). The non-federal respondents have no persuasive argument to the contrary. Although the Government contends that review nevertheless is unwarranted, this Court has often granted certiorari to articulate the correct principles of federal administration, rather than leaving FERC to correct case-specific errors on remand.

1. The Government agrees that the Ninth Circuit exceeded its authority in ordering FERC to reconsider allegations of market manipulation that FERC already had addressed in separate enforcement proceedings. That ruling runs afoul of *Mobil Oil Exploration & Producing Southeast v. United Distribution Cos.*, 498 U.S. 211 (1991), and is inconsistent with post-*Mobil Oil* circuit cases (*see* Pet. 26-28).

The non-federal respondents incorrectly argue (at 22-23) that those other FERC enforcement proceedings did not consider the manipulation allegations made in the PNW proceeding. But the evidence submitted in the reopened PNW proceeding concerned manipulation in the California markets, and, as the Government notes, the separate enforcement proceedings included PNW sellers. *See* Gov't Br. 5.

The non-federal respondents next argue that FERC failed to rely on *Mobil Oil* in its orders. *See* Resp. Br. 23-24. But the Court will "uphold a decision of less than ideal clarity if the agency's path may reasonably be discerned." *Bowman Transp., Inc. v. Arkansas-Best Freight Sys., Inc.*, 419 U.S. 281, 286 (1974). In this case, as the Government explains (at 5, 12-13), "read[ing] together" FERC's multiple orders of June 25, 2003, "adequately ground[s]" FERC's exercise of discretion to structure the complicated dockets arising out of the California energy crisis as it deemed best. *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, 497 (2004).

In all events, the non-federal respondents have no answer to petitioners' showing (at 24) that the allegations of market manipulation, even if proved, were irrelevant to FERC's equitable determination that refunds would be inappropriate.

2. The Government also agrees that the Ninth Circuit erred by failing to give proper deference to FERC's interpretation of Puget's complaint. *See* Gov't Br. 15. The Ninth Circuit's contrary interpretation does not withstand scrutiny. *See* Pet. 31; Gov't Br. 16.

Nevertheless, both the Government (at 16-17) and the non-federal respondents (at 26-27) erroneously assert that there is no conflict between the Ninth

Circuit's approach to interpreting this administrative complaint and the D.C. Circuit's well-established practices. Although the Ninth Circuit stated that it was "mindful" of the principle that it "owe[d] deference to FERC's interpretation of the scope of Puget's complaint," Pet. App. 31a, the court made no attempt to discern the "key element[s]," *Burlington Northern R.R. Co. v. ICC*, 985 F.2d 589, 594 (D.C. Cir. 1993), or the "entire thrust," *American Fed'n of Gov't Employees v. FLRA*, 796 F.2d 530, 533 (D.C. Cir. 1986), of the complaint, as the D.C. Circuit does. The court's citation of deference decisions does not make up for its failure even to mention, much less apply, the *analysis* of administrative complaints that forms the basis for the D.C. Circuit's deferential standard. Indeed, the Ninth Circuit's formalistic approach to interpreting administrative complaints squarely conflicts with the D.C. Circuit's contextual analysis.

Finally, the non-federal respondents do not seriously dispute petitioners' argument (at 32-33) that the Ninth Circuit undermined the notice that is an essential component of the rule against retroactive ratemaking. The court below subjected petitioners to potential refund liability – without the advance notice required for refunds under § 206 – for transactions alleged by the non-federal respondents to be worth more than $1 billion. *See* Pet. 34.[3]

3. Although the Government acknowledges that the Ninth Circuit erred, it maintains that review is premature. This case thus represents the latest in a series of California energy crisis cases in which the

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[3] The Ninth Circuit's ruling regarding where those sales occurred is not a "threshold" question. Gov't Br. 15 n.2. Properly interpreted, Puget's complaint encompassed purchases for ultimate consumption in the PNW only; the sale location is therefore irrelevant. *See* Pet. 30-31.

Government has rationalized Ninth Circuit errors that favor California purchasers on the asserted ground that FERC can fix those errors on remand. In *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S. Ct. 2733 (2008), this Court granted certiorari petitions by electricity sellers (and then reversed the Ninth Circuit's interpretation of the *Mobile-Sierra* doctrine) notwithstanding the Solicitor General's arguments that the decision below (a) was limited to "the highly unusual context of the 2000-2001 western energy crisis" and (b) "allow[ed] [FERC] sufficient discretion on remand to consider all relevant factors." 06-1454 *et al.* Gov't Br. 12.[4]

In this case, too, the Government invokes (at 9) the "highly unusual" nature of the California energy crisis to urge the Court to deny review. But this Court should not tolerate the Ninth Circuit's attempt to develop a set of crisis-specific administrative principles that consistently tip the scales in favor of California electricity purchasers.

Any effort to limit those principles to the California energy crisis also is unlikely to succeed. Federal agencies frequently conduct complex, nationwide administrative proceedings that involve a wide variety of actors and economically challenging circumstances. If the Ninth Circuit's rulings are allowed to stand, those actors will labor under uncertainty about whether their proceedings will be considered sufficiently "unusual" to warrant throwing out tradi-

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[4] Last Term, the Court granted certiorari in *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 129 S. Ct. 2050 (2009), notwithstanding the Solicitor General's argument that FERC could apply the court of appeals' incorrect standard in a way that would mitigate any relevant "policy concerns." 08-674 Gov't Br. 9.

tional standards of administrative deference in favor of this new body of "crisis" law.

The Ninth Circuit's rulings also stymie FERC's efforts to conclude the various proceedings arising out of the California energy crisis. Although the Ninth Circuit rightly "did not dictate what steps [FERC] must take on remand and did not hold that refunds would ultimately be required," Gov't Br. 14, the court expressed skepticism of the agency's ultimate conclusion, "urg[ing] [FERC] to further consider its decision[] on remand" in light of the Ninth Circuit's other energy-crisis-specific decisions. Pet. App. 36a. And, through the Ninth Circuit's decision to consolidate all California energy crisis FERC appeals before one three-judge panel without granting any en banc review, this case will remain under the supervision of the same panel that currently has pending hundreds of petitions for review of this and related FERC orders. Finally, the fact that a closed proceeding has now been reopened with a vastly greater scope and an additional $1 billion in alleged liability demonstrates sufficient prejudice to petitioners to warrant this Court's review.

In sum, this Court's review is urgently needed to restore normalcy to the administrative process for the energy crisis cases and to enable FERC to resolve the legal uncertainty that surrounds billions of dollars of transactions that took place almost a decade ago.

CONCLUSION

The petition for a writ of certiorari should be granted.

Respectfully submitted,

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No. 09-288

IN THE
Supreme Court of the United States

PUGET SOUND ENERGY, INC., ET AL.,
Petitioners,

v.

PEOPLE OF THE STATE OF CALIFORNIA, ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Ninth Circuit

MOTION FOR LEAVE TO FILE BRIEF OF LAW PROFESSORS AS *AMICI CURIAE* AND BRIEF OF LAW PROFESSORS AS *AMICI CURIAE* IN SUPPORT OF PETITIONERS

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October 8, 2009

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MOTION FOR LEAVE TO FILE BRIEF OF LAW PROFESSORS AS *AMICI CURIAE* IN SUPPORT OF PETITIONERS

Under Rule 37.2(b) of the Rules of this Court, *amici* law professors move for leave to file the accompanying brief as *amici curiae* in support of Petitioners. Petitioners and the federal Respondents (Bonneville Power Administration and the Federal Energy Regulatory Commission) have consented to the filing of this brief (and letters reflecting their consent have been filed with the Clerk), but counsel for *amici* was not able timely to receive consent from the non-federal Respondents to the filing of this brief, necessitating this motion.

Amici are law professors who teach and write in the area of administrative law. Harold H. Bruff is

the Charles Inglis Thomson Professor of Law at the University of Colorado at Boulder, where he teaches Constitutional Law, Administrative Law, and Separation of Powers. Ronald A. Cass is Dean Emeritus of Boston University School of Law, where he taught Administrative Law; he has also served as Chairman of the American Bar Association's Section on Administrative Law and Regulatory Practice. Ronald M. Levin is the Henry Hitchcock Professor of Law at Washington University School of Law, where he teaches Administrative Law and Legislation. Ernest A. Young is the Alston & Bird Professor of Law at Duke Law School, where he teaches Constitutional Law, Federal Courts, and Administrative Law.

Amici law professors should be granted leave to file the attached *amici curiae* brief.

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Questions Presented

1. Whether the Ninth Circuit erred in holding that the Federal Energy Regulatory Commission's ("FERC") use of a pre-enforcement evidentiary proceeding to inform its decision whether to enforce § 206 of the Federal Power Act, 16 U.S.C. § 824e, subjected to judicial review that agency's otherwise unreviewable choice not to initiate a § 206 enforcement proceeding.

2. Whether the Ninth Circuit improperly interfered with FERC's discretion to structure its own proceedings in ordering FERC to consider in one proceeding matters that FERC had determined were more properly addressed in a separate and ongoing proceeding.

3. Whether the Ninth Circuit exceeded its authority by rejecting FERC's interpretation of an administrative complaint.

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Interest of *Amici Curiae*[*]

The interest of the *amici curiae* is described in the accompanying motion for leave to file this brief.

Statement

This case raises important issues concerning the authority of courts to review agency determinations not to initiate proceedings as well as agency decisions about how to structure such proceedings. In *Heckler v. Chaney*, 470 U.S. 821, 831 (1985), this Court held that "an agency's decision not to prosecute or enforce, whether through civil or criminal process, is a decision generally committed to an agency's absolute discretion." In the present case, however, the Ninth Circuit critically undermined this principle by holding that an agency's nonenforcement decision becomes reviewable whenever an agency "has made a determination to adjudicate a dispute or take steps towards enforcing a violation of the law, the outcome it chooses is subject to judicial review." *Port of Seattle v. FERC*, 499 F.3d 1016, 1027 (9th Cir. 2007). This vague formulation threatens to trigger judicial review whenever an agency "takes steps" to investigate the circumstances of a complaint before ruling on whether to proceed with enforcement. If that becomes the law in other circuits, agencies will

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[*] Pursuant to Supreme Court Rule 37.6, counsel for *amici* represent that they authored this brief in its entirety and that none of the parties or their counsel, nor any other person or entity other than *amici* or their counsel, made a monetary contribution intended to fund the preparation or submission of this brief. Counsel for *amici* also represent that all parties were provided notice of *amici*'s intention to file this brief on September 30, 2009, and that all parties consented to waiver of the 10-day notice requirement in Rule 37.2(a).

face strong incentives *not* to take investigatory steps that would result in a more informed decision about whether to take enforcement action, and targets of investigations will be unable to rely on agencies' nonenforcement decisions for fear that a court may seize upon some preliminary "step" and reopen the case.

Enforcement discretion extends not only to initiation of a proceeding but also to decisions about how to structure a proceeding. This principle is central to the notion that agencies generally enjoy control over their own dockets. The Ninth Circuit's decision in the present case undermined this bedrock principle by ordering the Federal Energy Regulatory Commission ("FERC") to consider issues in *this* proceeding that it had chosen to address in separate proceedings, and by overruling the agency's construction of the present complaint as confined to a relatively narrow set of issues. This decision threatens the authority of agencies to formulate a coherent regulatory strategy, and it also injects considerable uncertainty into the enforcement process for private parties subject to agency enforcement actions.

Argument

I. The Ninth Circuit's Ruling Directly Undermines this Court's Ruling in *Heckler*.

Section 701(a) of the Administrative Procedure Act ("APA") permits judicial review of agency action "except to the extent that—(1) statutes preclude judicial review; or (2) agency action is committed to agency discretion by law." 5 U.S.C. § 701(a). The quintessential example of agency action "committed to agency discretion by law" is an agency's refusal to take enforcement action. In that situation, this Court held in *Heckler v. Chaney* that "the presumption is that judicial review is not available." 470 U.S. at 831. That is because "an agency's decision not to prosecute or enforce, whether through civil or criminal process, is a decision generally committed to an agency's absolute discretion." *Id.*

In *Heckler*, Texas inmates sentenced to die by lethal injection petitioned the federal Food and Drug Administration ("FDA") to prohibit the use of certain drugs for the purpose of human executions. The FDA Commissioner refused on the ground that the agency lacked jurisdiction over executions and, in any event, that state lethal injection laws posed an insufficient danger to public health to warrant expenditure of the agency's enforcement resources. *Id.* at 824-25. The FDA appears to have rendered its decision not to go forward solely on the basis of the materials submitted in the inmates' original petitions. Frequently, however, agencies wish to inform themselves further before deciding whether to take enforcement action. The present petition presents the question whether such information-gathering

takes the agency's ultimate decision not to proceed to enforcement outside the scope of *Heckler*'s presumption.

Investigatory steps taken prior to an agency's decision not to take enforcement action should not alter the basic presumption of nonreviewability for such decisions. The Ninth Circuit's contrary decision in the present case threatens to upset the settled law under § 701(a) of the APA, to impose perverse incentives on administrative agencies *not* to consider thoroughly the circumstances before deciding not to enforce, and to create unpredictability for the targets of agency investigations.

A. FERC's decision in this case amounted to an unreviewable decision not to initiate enforcement proceedings.

In this case, Petitioners asked FERC to impose a price cap on sales of power into Pacific Northwest markets equivalent to any price cap that FERC might impose on sales of power in California's centralized energy markets. FERC dismissed that complaint. Complications arose, however, after Petitioners first moved for rehearing, then sought to withdraw their complaint on the ground that FERC orders in related proceedings had provided the relief they sought. Various intervenors opposed this motion to withdraw, and FERC issued an order initiating a "separate preliminary evidentiary proceeding" to "facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest." Pet. App. 102a-103a. In other words, the allegations of the intervenors were of sufficient interest that FERC wanted to hear

more before making a decision whether to initiate a refund proceeding under § 206 of the Federal Power Act ("FPA"). After evidentiary proceedings before an administrative law judge ("ALJ"), the ALJ issued a report finding that the prices charged in the Pacific Northwest were not unjust and unreasonable and that a refund proceeding would likely be unworkable. *Id.* at 326a, 369a-370a.

Following the ALJ's report, FERC itself determined not to initiate proceedings under § 206 that could ultimately result in an order requiring refunds. It based that decision not only on the ALJ's conclusion that the relevant prices were not unlawful—a question on which FERC declined to make an explicit finding—but on its conclusion that, even if those prices *were* unlawful, various "equitable factors" weighed against enforcement action. These factors included:

- the fact that "an immense number of transactions [would be] subject to refund in th[e] case," requiring "prolonged time and effort to unravel," and that in many instances it would be "nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision," *id.* at 398a-399a;
- the involvement in the relevant transactions of a large number of governmental entities over whom FERC lacked jurisdiction to order refunds, *id.* at 394a-395a, 400a; and
- the unfairness of providing refunds to purchasers of power in the spot markets, vis-à-vis other utilities that engaged in a more

> prudent strategy for purchasing power on a long-term basis, *id.* at 397a-398a.

On rehearing, FERC reiterated that it was unwilling to expend "[t]he time and resources that must be devoted to refund calculations," especially when "such relief would arbitrarily remedy only a portion of the regional market." *Id.* at 442a, 436a.

No one disputes that, standing alone, FERC's decision declining to institute a § 206 proceeding on its own motion would have been unreviewable, based as it was on FERC's judgments about the lawfulness of the prices and the equities of the broader situation. That decision involved precisely the "complicated balancing of a number of factors which are peculiarly within [the agency's] expertise" that this Court found in *Heckler*. 470 U.S. at 831. In particular, FERC's consideration of the equities focused on whether enforcing the law against some parties would skew conditions unfairly in the broader market and whether the agency's enforcement resources might be better employed elsewhere.

The question is whether FERC's decision to seek more evidence before reaching that decision requires an opposite result. It would be odd if it did, because it is equally clear that the ALJ's recommendations were not themselves reviewable as they did not constitute final agency action. 5 U.S.C. § 704. Two unreviewable proceedings do not somehow add up to a reviewable one. The proceedings before the ALJ were simply an effort to help the agency make up its mind about whether to take enforcement action. Those proceedings did not somehow change the character of FERC's ultimate decision into a reviewable adjudication on the merits.

The Ninth Circuit held, to the contrary, that, "where FERC has made a determination to adjudicate a dispute or take steps towards enforcing a violation of the law, the outcome it chooses is subject to judicial review." *Port of Seattle*, 499 F.3d at 1027. But this holding ignores the actual character of FERC's decision in this case and is likely to engender confusion concerning precisely what "steps toward enforcing" are sufficient to trigger review. The FPA regulates the initiation of refund proceedings under § 206 with considerable precision. Section 206(a) requires that "[a]ny complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate . . . and the reasons for any proposed change or changes therein." 16 U.S.C. § 824e(a). Likewise, § 206(b) requires initiation of a proceeding to be accompanied by a precise "refund effective date" that importantly determines potential liability for a refund. 16 U.S.C. § 824e(b). All this means that, if FERC's decision to hold evidentiary proceedings before the ALJ in this matter amounted to an actual "determination to adjudicate a dispute" on its own motion, that determination would have been unlawful because it did not satisfy the requirements of § 206(a) and (b). Of course, FERC never intended its request to the ALJ to explore some of the underlying facts to amount to such a determination, and the Ninth Circuit was wrong to equate them.

The Ninth Circuit's alternate suggestion—that the ALJ proceedings amounted to "steps toward enforcing" the law—is of course true in a sense. Those proceedings were intended as a quick look at the facts to help the agency determine whether

concerns about the Pacific Northwest spot market warranted a full refund proceeding under § 206. But many actions are "steps toward enforcing" the law. An agency takes such a step when it accepts delivery of a petition seeking a § 206 petition, or when a commissioner issues a press release expressing concern about conditions in the market or when the agency uses formal or informal processes to obtain information from regulated entities. Even the agency's purely internal deliberations about whether to proceed constitute "steps toward enforcing" the law. Any rule that suspends *Heckler*'s presumption of nonreviewability and renders agencies subject to judicial review whenever they take such steps is likely to engender hopeless confusion about what steps count and what steps do not.

One possible way to alleviate such confusion arises from the Court of Appeals' comment that, "[w]hen an agency *has instituted* proceedings, meaningful standards exist to review what the agency has done." *Port of Seattle*, 499 F.3d at 1027. But the Ninth Circuit confused the ALJ's nonfinal recommendation that the prices were not unjust or unreasonable—which *was* based on an application of the statutory standard and thus the sort of question that a court could review—with FERC's decision not to initiate an enforcement action on its own motion under § 206. The latter decision, which was the only *final* agency action and thus the action actually before the court, was not based on the reasonableness of the relevant rates under the statute but rather on the equitable factors listed above. Those factors were quintessentially *Heckler*-type factors, grounded in the systemic fairness of enforcement and the optimal allocation of the agency's enforcement resources.

See generally Ronald M. Levin, *Understanding Unreviewability in Administrative Law*, 74 Minn. L. Rev. 689, 745 (1990) (noting that the courts generally refuse to review "agency operations that are closely related to the agency's management of its workload"). If FERC's decision based on those factors would have been nonreviewable in the absence of the ALJ proceeding—as it surely would have been—then the fact that FERC tasked an ALJ to take some evidence on the justness of the rates cannot change the outcome.

The Ninth Circuit may have been concerned that agencies will disguise decisions on the merits as decisions not to enforce, in order to avoid judicial review. That might have been the case if FERC had taken evidence through an ALJ on the justness and reasonableness of the rates, then decided not to initiate a § 206 proceeding on the ground that the rates were just and reasonable. In that scenario, the ALJ proceeding seems to offer an effective but nonreviewable substitute for the § 206 proceeding itself, thereby circumventing the statutory scheme's provision for judicial review. But that is not this case. FERC's ultimate decision not to go forward was based on equitable factors about enforcement resources, not the merits of the claim for a refund, and that conclusion did not critically rely on the ALJ's determination about justness and reasonableness. *See* Levin, *supra*, at 745 (observing that unreviewable enforcement decisions "may not reflect conclusions on the merits of the petitioner's substantive claims"). *Heckler* should be applied with a pragmatic eye to preventing procedural dodges meant to avoid judicial review, but the Ninth Circuit's rule that *any steps* toward enforcement

obviate the presumption of nonreviewability sweeps far too broadly.

B. The Ninth Circuit's novel rule will have perverse consequences for agency decisionmaking and impose uncertainty upon the targets of agency investigations.

Under the Ninth Circuit's ruling, an agency's decision "'not to prosecute or enforce, whether through civil or criminal process,'" is unreviewable *unless* the agency "commit[s] resources" to making that very decision. *Port of Seattle*, 499 F.3d at 1027 (quoting *Heckler*, 470 U.S. at 831)). In addition to being in conflict with the decisions of several other circuits and settled law of this Court, the Ninth Circuit's ruling discourages agencies from devoting resources to careful decisions about enforcement, thereby leading to bad outcomes in what are routinely complex regulatory areas.

As noted, it is plain from the Ninth Circuit's decision that, had FERC simply decided not to enforce § 206 of the FPA at the outset, its decision would not have been reviewable under the APA, in accordance with this Court's decision in *Heckler*. *See* 470 U.S. at 838. Yet, because the Commission recognized that the matter of reasonable energy prices during this time period raised complicated questions, it went beyond its necessary functions and created a separate proceeding to determine whether it should enforce § 206 of the FPA. By holding that FERC's careful actions render its decision not to enforce § 206 reviewable, the Ninth Circuit has encouraged agencies to forgo holding any sort of special proceedings that would enable them to make better decisions to enforce or not. From this point

forward, agencies that are "on the fence" about enforcing a particular provision will know that the best way to avoid judicial review should they decide not to initiate an enforcement proceeding—which may lead, as it did in this case, to protracted judicial proceedings that will undoubtedly take up copious amounts of time and financial resources—is simply to decide not to act to obtain additional information to inform that decision.

Although the fact that such skewed incentives will clearly lead to detrimental results is obvious, it is worth delineating precisely what is at stake for agencies and, in turn, for citizens. At issue in this case alone are hundreds of thousands of energy purchase transactions, in total worth billions of dollars. As we have stated, FERC would have been in a better position before the Ninth Circuit and in terms of managing its dockets and resources had it simply decided, without further investigation into these complex transactions, that enforcement of § 206 was undesirable for any number of reasons. In critical and complicated areas such as energy regulation, the agencies, and accordingly citizens, are better served if they can properly assess the issues they regulate and evaluate whether action is appropriate. To instead reward uninformed decisions not to act is to undermine the usefulness and efficacy of agencies, and to call into question their ultimate decisions.

Finally, the Ninth Circuit's ruling will have negative consequences for targets of agency investigations. If an agency decides not to enforce a particular provision, the private parties that would have been involved in such an action should be able to rely upon that decision and proceed with their

businesses and so forth. If those parties instead believe that a court may come along and undo the agency's decision to refrain from enforcement, they will be in a position of hanging fire—waiting for months if not years for some sort of finality beyond the agency's final determination.

II. The Ninth Circuit's Decision To Direct FERC To Consider Specific Factors on Remand and To Reject FERC's Interpretation of the Complaint Violates Basic Canons of Administrative Law.

The decision whether or not to initiate enforcement proceedings is not the only critical aspect of an administrative agency's enforcement discretion. That discretion also extends to critical aspects of the form that such proceedings should take. Should action against multiple defendants take place through multiple focused actions or in one consolidated proceeding? Which aspects of a multifaceted regulatory problem should be undertaken first? Which complaints initiated by private parties will provide the best vehicle for resolving a particular issue, and which aspects of the relevant disputes should be reserved for other proceedings? All of these decisions are critical elements of the agency's authority to formulate a coherent regulatory strategy. *Cf. Massachusetts v. EPA*, 549 U.S. 497, 527 (2007) ("[A]n agency has broad discretion to choose how best to marshal its limited resources and personnel to carry out its delegated responsibilities.").

The present case illustrates just how critical these elements of enforcement discretion are. The 2000-2001 energy crisis in California and other

western markets involved hundreds of thousands of transactions, dozens of major private players, multiple governmental jurisdictions, and a variety of natural and human causes. Congress tasked FERC with devising a coherent regulatory response to this crisis, and that task required FERC not only to decide *whether* to act but *how*—which enforcement actions to bring against which entities to consider which issues. The Ninth Circuit failed to respect FERC's choices in this area by ordering FERC to consider certain market manipulation allegations in the Puget Sound proceeding rather than in other proceedings that FERC had already initiated, and by overriding FERC's construction of Puget Sound's complaint to expand the present proceeding beyond the scope that either FERC or the initiating party believed appropriate. In so doing, the Ninth Circuit upset settled principles of administrative law, interfered with FERC's regulatory approach to a particular regulatory problem of massive importance, and deprived private parties of their ability to rely upon an agency's chosen way of framing a dispute.

A. The Ninth Circuit usurped FERC's enforcement discretion by ordering the agency to consider factually distinct allegations that FERC had chosen to consider in separate proceedings.

The Ninth Circuit mandated that, on remand in the present proceeding, FERC must consider allegations of market manipulation by Enron and others submitted late in the present proceeding. It reached that conclusion notwithstanding FERC's statement grounding its decision not to proceed on "the complete record, including the material submitted in the [additional] filings" alleging market

manipulation. Pet App. 419a. The Ninth Circuit was unmoved by FERC's contemporaneous decision to open new proceedings specifically targeted at market manipulation in California and the Pacific Northwest. *See American Elec. Power Serv. Corp.*, 103 FERC ¶ 61,345 (2003); *Enron Power Mktg., Inc.*, 103 FERC ¶ 61,346 (2003). That decision disregarded the agency's "inherent power[] . . . to control its own docket." *GTE Serv. Corp v. FCC*, 782 F.2d 263, 274 n.12 (D.C. Cir. 1986).

This Court has held that "[a]n agency enjoys broad discretion in determining how best to handle related, yet discrete, issues in terms of procedures and priorities," and that an agency "need not solve every problem before it in the same proceeding." *Mobil Oil Exploration & Producing Southeast Inc. v. United Distrib. Cos.*, 498 U.S. 211, 230-31 (1991). Just as a prosecutor may choose to charge multiple defendants in the same proceedings, or to prosecute individuals in separate proceedings, or even to let some potential defendants go in order to concentrate on more pressing targets, so too an enforcement agency enjoys broad and often unreviewable discretion to shape its enforcement agenda. The fact that a reviewing court might have chosen to organize the proceedings differently is no basis for judicial interference with the choices the agency actually made.

The Ninth Circuit seemed to think that, once it had determined to review FERC's decision at all, that determination exhausted the relevance of *Heckler* and § 701(a). The Court of Appeals' decision thus may well be taken to stand for the proposition that *only* bare decisions to enforce or not enforce at all come within *Heckler*'s presumption of

nonreviewability. But that would read *Heckler* far too narrowly. Certainly the FPA provides no standards limiting the discretion of the agency to separate issues into multiple proceedings; there is, under § 701(a), "no law to apply," *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 410 (1971), on that question.

Moreover, the agency's decision whether to separate issues into multiple proceedings or to combine them in one is likely to rest on the same sorts of grounds as a decision not to bring an enforcement action in the first place. *See Heckler*, 470 U.S. at 831-32 (listing considerations behind a decision not to enforce). Separate proceedings may permit more efficient use of the agency's resources by focusing particular proceedings on particular issues. Likewise, separate proceedings may further goals of systemic fairness by permitting the agency to group those parties who are most similarly situated. All of these considerations are within the expertise of the agency, and courts have no comparative advantage that would warrant second-guessing the agency's decisions in this regard.

B. The Ninth Circuit improperly failed to defer to FERC's construction of Puget Sound's complaint.

As demonstrated in Petitioners' brief, other courts have consistently deferred to an agency's judgment as to how best to construe a party's complaint filed with the agency. The most obvious reason is simply that the agency, dealing as it does with such complaints on a day-to-day basis, will generally have greater expertise on such questions than the reviewing court. But, to the extent that a complaint

genuinely is ambiguous, the decision to construe it narrowly or broadly takes on the more general trappings of other decisions about the scope and structure of agency litigation. Such decisions thus likewise fall within the enforcement discretion of the agency recognized in *Heckler* and § 701(a).

The present case is illustrative. Petitioner Puget Sound Energy, Inc. initially filed a narrow complaint seeking no refund at all, but rather a prospective price cap to guard against a "whipsaw" effect should FERC decide to cap prices for energy sold into California's centralized markets but not prices for energy bought to serve demand in the Pacific Northwest. Later intervenors, which never filed their own complaints, sought to add claims for refunds to Puget Sound's complaint, and still later certain intervenors introduced evidence of market manipulation. Even assuming that Puget Sound's complaint was ambiguous, it was within the discretion of FERC to conclude that that complaint did not provide the right context for addressing this broader set of issues.

Just as this Court must choose the best "vehicle" for deciding a particular issue from among different cases presented for its review, so too an administrative agency needs a certain degree of discretion to choose whether or not to confront a particular issue in a particular case. This retail discretion concerning which issues to address within a case parallels the agency's undisputed discretion not to pursue a case at all. As in the latter situation, the relevant statutes provide no directive to construe complaints narrowly or broadly, and the relevant considerations are similar to those in *Heckler* itself. Respect for the agency's enforcement discretion is

thus best reflected in a strong principle of deference to an agency's construction of the complaint before it.

C. The Ninth Circuit's ruling will create gross inefficiencies for agencies and harm the targets of agency investigations.

The Ninth Circuit's rejection of FERC's interpretation of the administrative complaint and its directive to consider specific factors on remand not only violates settled law, but will no doubt have perilous consequences for agency decisionmaking and the targets of agency investigations.

First, the Ninth Circuit's decision permits, and even directs, courts to engage in the micromanagement of basic agency decisions such as how to structure enforcement proceedings. The law is clear that agencies should maintain control over these decisions, precisely because, based upon their expertise, they are best-suited to make them. Appellate courts, with little to no knowledge about the competing needs for resources of particular agencies, will only create gross inefficiencies if they are allowed to direct agencies to rethink the kind of basic decisions they are entrusted with making every day.

Second, beyond creating a basic inefficiency by permitting courts to undertake the micromanagement of decisions about which they have no expertise, the Ninth Circuit's ruling will lead to further inefficiency by causing agencies to act "defensively." That is, if agencies are aware that their decisions can later be meddled with by unknowledgeable courts, they will likely act preemptively and structure their decisions in ways to insulate them from future judicial

direction. Because such decisions will not be based solely on the most appropriate way to regulate an agency's given area, they will necessarily undermine the efficiency of the regulatory regime.

Finally, the Ninth Circuit's ruling will harm not only agencies, but also the targets of agency investigations. Private parties who may be the targets of or otherwise involved in an agency enforcement action need to be able to rely on the agency's decision to structure proceedings in a particular way. Parties interested in market manipulation allegations, for instance, might well have decided to participate in FERC's proceedings devoted to that issue, rather than in the present proceeding. The targets of agency action should be able to confine their submissions to the issues raised by an agency in a particular proceeding without having to worry that a reviewing court may choose to reconfigure the proceedings long after the fact. The Ninth Circuit's ruling substituting its own ideas about structuring the proceedings directly undermines this principle.

Conclusion

The petition for a writ of certiorari should be granted.

Respectfully submitted,

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